

Convergence: Natural Gas and Electricity in Washington

A Survey of the Pacific Northwest Natural Gas Industry
on the Eve of a New Era in Electric Generation

WASHINGTON STATE

Office of Trade & Economic Development

Martha Choe
Director

David Warren, P.E.
Assistant Director for Energy Policy

May 2001

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**Energy Policy Division
925 Plum Street SE, Bldg 4
PO Box 43173
Olympia, WA 98504-3173**

May 2001

Printed copies of this report are available by calling (360) 956-2096

This document is also available on the Internet at <http://www.cted.wa.gov>



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Editor

Arne Olson, Washington Office of Trade and Economic Development

Contributing Authors

Roel Hammerschlag, Institute for Lifecycle Energy Analysis

Rick Kunkle, P.E., Washington State University Cooperative Extension Energy Program

Jim Lazar, Microdesign Northwest

Arne Olson, Washington State Office of Trade and Economic Development

David Warren, P.E., Washington State Office of Trade and Economic Development

Stacey Waterman-Hoey, Washington State University Cooperative Extension Energy Program

Acknowledgements

The Washington State Office of Trade and Economic Development would like to recognize the following organizations for their generous donations of staff time and resources in review of earlier drafts of this report:

Energy and Environmental Analysis, Inc.

Northwest Gas Association

Northwest Industrial Gas Users

NW Natural

Northwest Power Planning Council

Washington Utilities and Transportation Commission

PG&E National Energy Group

Puget Sound Energy, Inc.

Williams Gas Pipeline

This recognition does not imply endorsement of any of the findings or conclusions of the report.

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Executive Summary

This report examines trends in the demand for and supply of natural gas for Washington and the Pacific Northwest in light of current plans to construct several thousand megawatts of new natural gas-fired electric generating capacity. Construction of even a fraction of the projects that have been proposed for Washington, Oregon, and Idaho will greatly increase the region's demand for natural gas. This raises serious questions about the ability of the region's gas delivery system to meet this new demand without adverse consequences for existing natural gas consumers. The extreme price events of the last several months, caused in part by a sudden, large increase in consumption of natural gas for electricity generation, provide a cautionary example of the strong forces that can be unleashed by unplanned demand growth.

Past and Present Trends in the Natural Gas Industry

Natural gas was introduced to the Pacific Northwest with the completion of the Northwest Pipeline system in 1957, which connected the region to natural gas fields in the Rocky Mountains. In the 1960s, additional pipelines were constructed that connected the region to Canadian sources of gas. Within local communities, gas is distributed by four investor-owned utilities and three cities.

Until 1985, the price of wholesale natural gas was regulated by the federal government. Producers could earn only a "fair rate of return" on investments in natural gas production. As a result, very few gas wells were drilled, and by the mid-1970's, demand for natural gas began to outstrip available supply. Deregulation of the natural gas industry began during the 1980s. Prices were decontrolled federally, and the state allowed customers to purchase their own gas supplies. After 1985, wholesale prices plummeted and consumption began to grow rapidly.

In the 1990s, natural gas began to be burned in large quantities for electric generation. The new combined cycle combustion turbine technology, coupled with low gas prices, made gas the fuel of choice for electric generation. Applications to construct over 2000 megawatts (MW) of gas-fired electric generating capacity were approved by the Washington Energy Facility Site Evaluation Council by 1996. A 248 MW plant was completed in 1997 and 900 MW of gas-fired capacity came on line in Oregon and Idaho. Over 12,000 MW of new natural gas-fired generation are in various stages of construction, permitting, or planning in the Pacific Northwest. If even half of these plants were built, the region's natural gas consumption would grow by 50%.

Whether this level of construction poses problems for the industry depends on the timing of both new power plants coming on line and expansion of the region's ability to deliver low-priced gas. If pipeline expansions precede or accompany the interconnections of new plants and if new gas fields are brought on line at a reasonable cost, then increased demand will be accommodated with minimal disruption to existing customers. But if all of the necessary events don't occur in the proper sequence, the industry may experience price spikes leading to temporary economic dislocation, long-term upward pressure on gas prices, or both.

Moreover, the Northwest will increasingly be subject to forces over which it has no control. Demand from new plants in other western states, combined with increased pipeline capacity from producing areas in the Rockies and Western Canada to East Coast markets, will place pressure on the Northwest's natural gas infrastructure even if the region doesn't build a single new plant. The convergence of the electricity and natural gas industries means that these effects will also be felt in electricity markets.

The Events of 2000 and Early 2001

The extreme consequences from the events of Summer/Fall 2000 raise a number of questions about the appropriateness of existing company strategies and regulatory policies. The seeds of this situation date back to the early 1990s, when the West Coast was awash in cheap energy. Depressed gas prices led to limited exploration, and low electricity prices caused increasing pressure to deregulate retail electricity markets, creating regulatory uncertainty that inhibited the construction of new power plants. By the end of the decade, electric loads were growing rapidly, but the impact was masked by favorable weather and hydroelectric conditions.

All of this came to a sudden end in the summer of 2000. Sustained hot weather in California meant high levels of demand for electricity, while drier than average hydroelectric conditions meant reduced hydropower exports from the Northwest to California. Electricity prices spiked to record levels in June, and the market endured repeated, sustained periods of high prices throughout the summer. Greatly increased use of gas-fired generators meant that price pressures spilled over into natural gas markets.

By November and December, the combination of high prices, reduced inventories of natural gas in storage, and heavy reliance on gas for electric generation created monumental challenges. Temperatures were well below average across the country, and gas storage was at critical levels, particularly in California. Pipeline capacity into California and from the California border to major markets within the state became severely constrained, leading to huge differentials in the price of natural gas at various locations in the west. While wholesale gas prices in Wyoming and Alberta were frequently less than one-half the levels in the Northwest and California, pipeline capacity limitations meant that local market prices for natural gas would soar.

Three of Washington's natural gas utilities implemented rate increases in January, 2001 resulting in gas bills that were 50% to 90% higher than they were at beginning of 2000. Electric utilities caught short of power by dry hydroelectric conditions imposed temporary surcharges as high as 58% on electric rates to recover power purchased at extremely high prices. A number of large energy users curtailed production due to high utility costs for both gas and electricity, and several that were exposed to market electricity prices began operating diesel generators in late 2000.

Weather in December, 2001 did not reach anywhere near record cold levels in the Northwest, so the strain on the system could be much greater. Plans to greatly expand gas-fired electricity generation up and down the West Coast could lead to further strains on natural gas supply and deliverability, especially in the near term.

Natural Gas Pipelines Serving the Pacific Northwest

The Pacific Northwest is served by two interstate pipelines operated by the Northwest Pipeline Corporation, a subsidiary of Williams, and PG&E Gas Transmission, Northwest (GTN). These pipelines deliver natural gas from Canadian and domestic sources to customers in Washington, Oregon, California and other western states. Shippers, including local distribution companies, large industrial customers, and energy marketers purchase capacity on the pipelines to deliver gas from particular suppliers and receipt points on the system to particular delivery points.

Northwest Pipeline is a bi-directional pipeline that can deliver gas either from supply basins in the Rocky Mountains or from Canada through an interconnection with Westcoast Pipeline at Sumas, Washington. Northwest Pipeline interconnects with local utilities along the I-5 corridor, enters eastern Washington through the Columbia Gorge, and connects to utilities in eastern Washington via

a spur that ends in the Spokane area. Gas can flow from either Canadian or Rocky Mountain sources to the Pacific Northwest, as long as the market isn't attempting to flow too much gas in one direction. Approximately 73% of the natural gas on Northwest Pipeline is Canadian gas that enters the pipeline at Sumas, Washington or Stanfield, Oregon. However, contracted supplies don't always match actual gas flows due to a phenomenon called displacement, in which contracted gas flows in opposite directions negate each other. On a contractual basis, between 53% and 68% of the gas on Northwest Pipeline comes from Canada.

Prices at key delivery points on Northwest Pipeline have a significant influence on natural gas flows. When Canadian prices are higher than domestic prices, as has been the case recently, shippers want to move natural gas north from the Rocky Mountain region to the Pacific Northwest. However, under certain conditions, the pipeline becomes constrained and contract demand must be met with gas flows from the other direction. When there is a significant disparity between the price of natural gas at different points in the system, this can require the use of operational flow orders, requiring certain shippers to flow gas in a particular direction, in order to achieve system balance. Such an order was called on Northwest Pipeline in November, 2000, with severe consequences for some market participants.

The GTN pipeline connects the region with gas supply in Alberta. The GTN system is unidirectional; gas flows southbound from its Kingsgate, British Columbia interconnection with TransCanada, enters Washington near Spokane, crosses into Oregon south of the Tri-Cities, and continues to the California-Oregon border near Malin, Oregon. The majority of gas transported on the GTN system is delivered to California, but additional demand in this region could be accommodated through expansion. GTN interconnects with the Northwest Pipeline near Stanfield, Spokane, and Palouse, Washington where gas is frequently exchanged between the pipelines.

GTN has been operating at or near capacity for a number of months. The northern part of the system has been operating at 90 - 100% of capacity, depending to some degree on supply basin pricing dynamics. The southern end of the system has been operating at virtually 100% capacity since summer, 2000.

While the existing pipelines are fully subscribed, each has the ability to expand its capacity. The first step is to announce an "open season" in which any shipper can request and commit to paying for additional capacity. The cost of additional capacity can be "rolled in" to rates paid by existing customers, or charged only to new shippers, known as "incremental" pricing. Pipeline expansion is regulated by the Federal Energy Regulatory Commission (FERC.)

Northwest Pipeline recently completed an open season for expansion from Sumas to Chehalis. This will allow additional daily flows of 224,000 decatherms (or 224 MDth) per day, enough to supply two 600 MW power plants. Northwest Pipeline has additional plans to fix an existing constraint in the Kemmerer, Wyoming region. Williams, parent company of Northwest Pipeline, and BC Hydro are planning a 90 MDth/day pipeline project from Sumas, Washington to Vancouver Island, called the Georgia Strait Crossing project.

GTN recently announced the results of a similar-sized open season, in which the winning bids were submitted by power generating companies. Interest was expressed in an additional 2,000 MDth/day of gas deliverability, roughly ten times the 200 MDth/day that was proposed. As a result, GTN is planning for an additional expansion targeting a 2003 in-service date.

Natural Gas Production

Canadian natural gas comes from fields in the far north of British Columbia and Alberta, a geologic area known as the Western Canadian Sedimentary Basin (WCSB). It is piped south either through British Columbia on a pipeline owned by Westcoast Energy, Inc., or through Alberta on a pipeline owned by TransCanada to Kingsgate. The past five years have been a period of soaring activity in the Canadian gas industry. The number of wells drilled annually has more than doubled since 1995. However, increased drilling has not necessarily led to major increases in gas supply, as the size of the gas deposits now being developed is much smaller than in the past.

About half of U.S. reserves are in Texas, Louisiana, and in offshore wells in the Gulf of Mexico, and a quarter are in the Rocky Mountain states of New Mexico, Wyoming, and Colorado. After falling off during the 1990s, natural gas drilling in the U.S. has picked up dramatically over the past 18 months. The Rocky Mountain states are the most important source of domestic natural gas supply to the Pacific Northwest, but new supplies anywhere on the continent will increase supply available to the Northwest by displacing gas closer to the region.

One of the more promising new domestic source of natural gas is coal bed methane. Coal bed methane development could contribute significantly to meeting natural gas demand, but it is expensive and involves difficult environmental issues not present with conventional gas production.

Alaska's North Slope is potentially the largest source of new natural gas resources. A number of projects are under consideration that would bring Alaska gas to markets in Canada and the lower 48 states; competing pipeline projects would follow the McKenzie River or the Alaska-Canada Highway into northern British Columbia. New Canadian sources of natural gas include coal bed methane in the WCSB and so-called "Frontier" gas in the far north of Canada.

If the price of gas stays high enough for long enough, it may become economic to invest in large-scale facilities for importing liquefied natural gas (LNG). Increased imports of LNG in the short term are most likely to come from the Middle East, where vast natural gas reserves remain largely untapped, to the East Coast. Plans have recently been announced to explore bringing LNG to California from gas fields in Australia.

While new gas supplies are being located and developed continuously, production at existing wells continues to decline. Even if production from new supplies outpaces depletion of existing resources, the cost of new supplies may continue to rise. Diminishing reserves among traditional large-pool resources and higher costs of bringing large new sources of gas such as Canadian Frontier gas or Alaska gas to the lower 48 states may not be entirely offset by advancements in exploration and drilling technology and improvements in delivery infrastructure.

Conclusions and Recommendations for Further Study

It is increasingly apparent that wholesale electricity and natural gas prices are subject to extreme price volatility, and increasing convergence of the electricity and natural gas markets means that extreme events are likely to affect both markets simultaneously. This has a number of important implications:

- Electric utilities may wish to review resource plans in light of the newly understood risks. Utilities have a variety of tools at their disposal to protect against price volatility. Each carries a unique risk profile; choices made will reflect company risk tolerance. The state may wish to consider ways to encourage utilities to maintain diverse resource portfolios.

- The potential for simultaneous price spikes in electricity and natural gas markets suggests that ownership of gas-fired resources may not provide much of a price hedge. Utilities may wish to consider fixed cost resources such as wind generation or energy efficiency. The state may wish to consider ways to encourage additional investment in energy conservation and renewable resources as a hedge against volatile natural gas prices.
- Regulatory policies can have a major impact on company purchasing strategies. Purchased gas adjustment mechanisms allow natural gas utilities in Washington to pass the risk of market price volatility on to retail customers. The Washington Utilities and Transportation Commission (WUTC) may wish to review existing policies in light of new information about the extent of gas price volatility, to ensure that they continue to provide appropriate incentives for companies to make good resource management decisions and to protect consumers from bad ones.
- Retail energy rates that better reflect wholesale market conditions might encourage more conservation during times of tight supplies. Utilities and regulators should consider mechanisms that would encourage utilities and customers to better respond to market conditions by managing customer demand, while ensuring that customers retain the value of rate-based resources and are given the tools they need to respond to changing rates.

New natural gas-fired power plants will greatly increase the region's demand for gas, even if only a portion of planned projects are actually constructed. The state may wish to:

- Consider addressing as part of the energy facility siting process the potential cumulative impacts of all approved power plants on regional natural gas supply. A study of these impacts, combined with a condition that plants begin construction within a specified period of time after approval, would ensure that cumulative impacts on all consumers of natural gas are well understood.
- Consider how new gas-fired generators will affect the region's ability to meet simultaneous peak demands on the electricity and natural gas systems. Requiring new generators to demonstrate sufficient pipeline or storage capacity for their peak needs, or allowing limited use of a backup fuel such as distillate oil or liquefied natural gas, would help to alleviate pressure on both systems.
- Consider policies that would encourage the direct use of natural gas at the customer location and improve the efficiency of existing uses of natural gas. These efforts would reduce the demand for gas-fired electric generation and provide for more efficient utilization of available natural gas resources.

Increased pipeline capacity from producing areas in Canada and the U.S. Rockies to markets in the Midwest and East Coast regions means that the price of natural gas for Northwest customers will be much more closely tied to continent-wide events than in the past. To prepare for this eventuality, the state may wish to:

- Examine projected natural gas supply and demand on a continent-wide basis, to determine the likelihood that increased demand in this and other regions can be met with additional supplies, and the effect this will have on competition for and prices of resources that have traditionally supplied the Northwest.

- Examine the potential for new sources of natural gas production in areas that will realistically meet future demands in the Northwest. This would include an examination of the economic, technical, and political state of development of new resources in the Rocky Mountain area (including coal bed methane), the Western Canadian Sedimentary Basin, the far North of Canada, and the Alaska North Slope, and an analysis of how gas from those areas may be delivered to this region.

Section 1. Past and Present Trends in the Natural Gas Industry

Natural Gas was introduced to the Pacific Northwest with the completion of the Northwest Pipeline system in 1957. This pipeline, now owned and operated by Williams, connected Spokane, Portland and Seattle to natural gas fields in Wyoming, Colorado, and New Mexico. Connections were installed to most major communities in the state, including Wenatchee, Ellensburg, Pasco, Aberdeen, and Bremerton. Prior to that time, urban areas were served with manufactured gas (made from coal), but industrial processes relied almost exclusively on petroleum, coal, and wood for process heat needs.

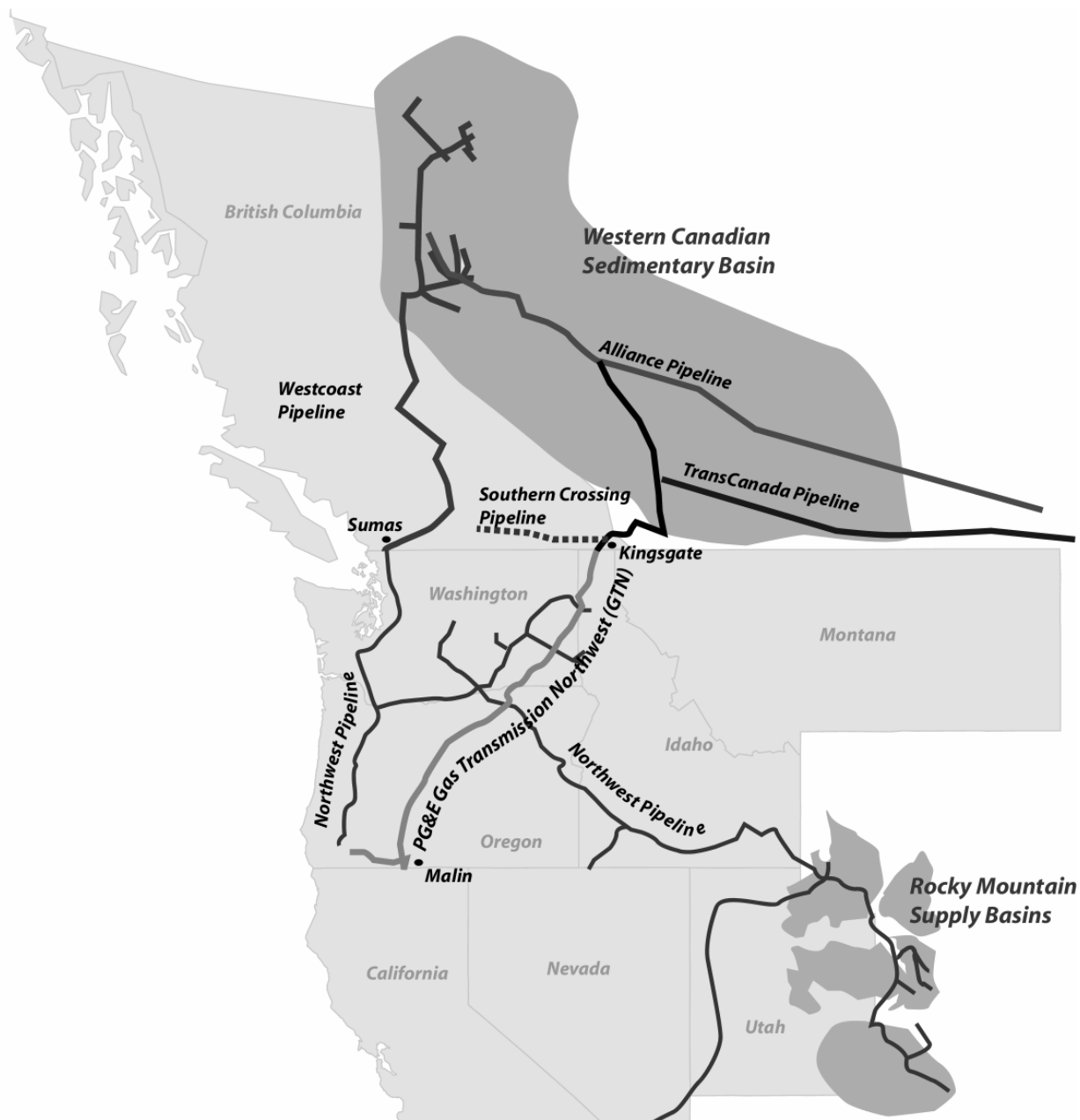


Figure 1.1. Major Natural Gas Pipelines Serving the Northwest

By the 1950s, natural gas fields were developed in northern British Columbia and Alberta, and the Westcoast Pipeline system was constructed to the Lower Mainland of British Columbia and connected to Northwest Pipeline at Sumas, Washington. Since that time, the state of Washington has received gas from both domestic and Canadian sources.

The PG&E Gas Transmission Northwest (GTN) pipeline (frequently referred to as “PGT”, after the previous name, “Pacific Gas Transmission”) went into service in 1961 as the U.S. leg of a pipeline from Alberta to California. Although primarily constructed to serve the California market, the pipeline also serves customers in the Pacific Northwest.

Within local communities, gas is distributed by four investor-owned utilities, sometimes called local distribution companies (LDCs), and three cities. These companies purchase gas at market hubs and transport the gas through the interstate pipeline system to the “city gate”, where it enters the local distribution system. Retail rates of LDCs are regulated by the Washington Utilities and Transportation Commission (WUTC). Local gas distribution company service territories are depicted in Figure 1.2. Many large customers arrange for their own gas supplies from market hubs and purchase transportation services from interstate pipelines and/or LDCs.

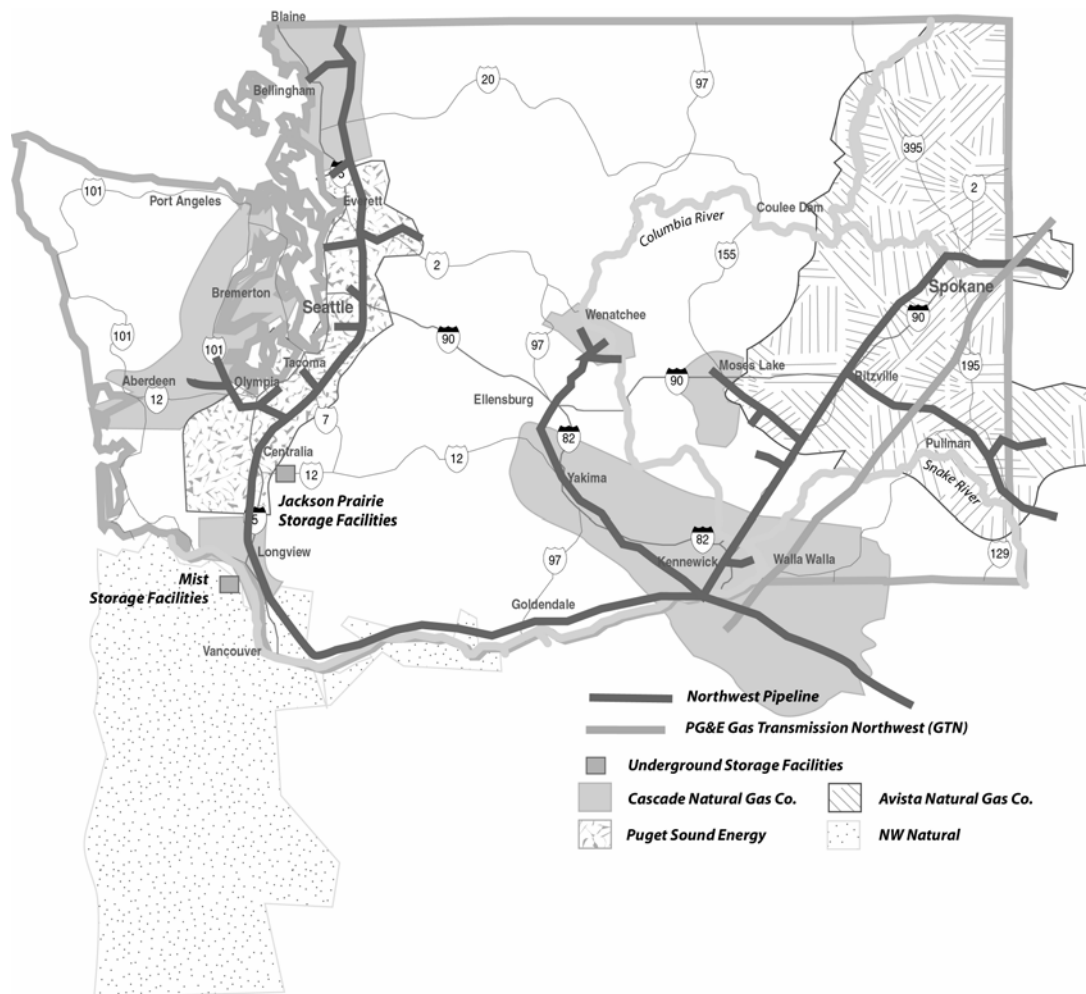


Figure 1.2. Natural Gas Utility Service Areas in Washington

Pre-1985: The Natural Gas Industry Under Federal Regulation

The U.S. natural gas industry dates back more than a century. Until passage of the Natural Gas Policy Act of 1978, gas production was treated as a by-product of oil production. In many oil wells, the pressure that forced oil to the surface was actually that of natural gas which was a part of the same formations. The Federal Power Commission, now the Federal Energy Regulatory Commission (FERC), regulated the price of natural gas from the well to the pipeline, and the price charged by pipelines to deliver that gas to local gas utilities. State regulatory commissions regulated local gas utilities' prices to retail customers. Gas prices were regulated from the point of production to the point of use.

This price regulation meant that gas producers would receive only a "fair rate of return" on gas well investments, and could not make "entrepreneurial" profits from gas field development. As a result, very few gas wells were drilled. Most gas production remained a by-product of oil well development, where profits were not regulated.

This fact was very important to the evolution of the natural gas market in the state of Washington. Washington was connected to both domestic and Canadian gas producers. The U.S. producers were subject to federal price controls, while the Canadian producers were not.

By the mid-1970s, the supply of natural gas was less than the demand for that gas in the U.S. Industrial customers such as pulp and paper mills, which used gas in large quantities, were increasingly subjected to interruptions to meet the needs of core market residential and commercial customers. These customers paid lower prices for gas because they were interruptible, and they maintained storage tanks of oil for use during periods of interruption.

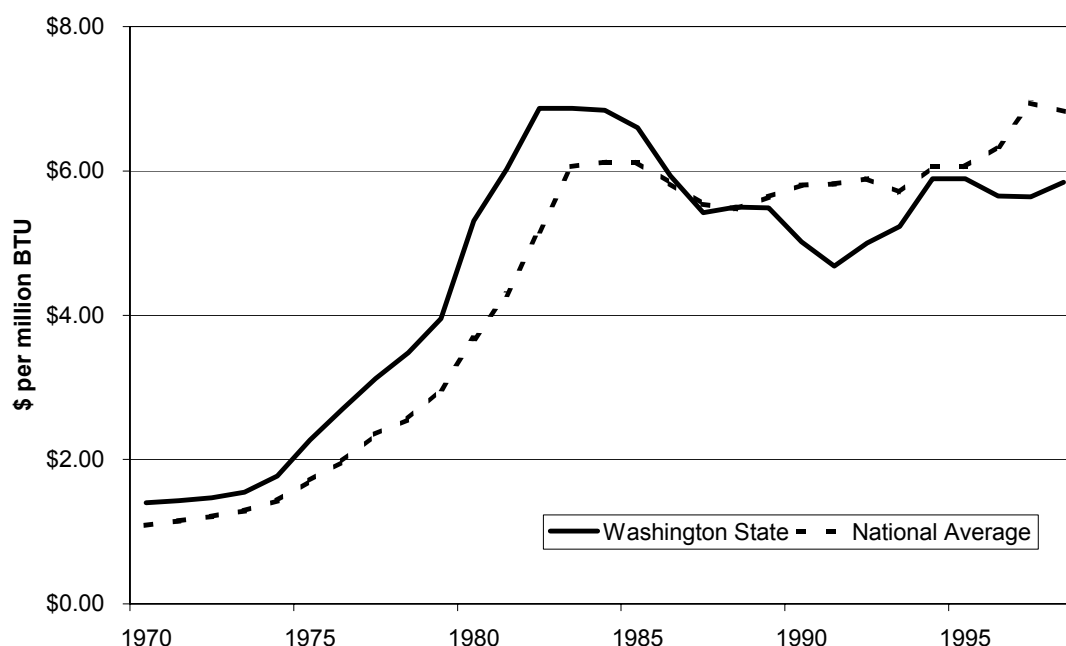
The supply of gas became so critically low that in the early-1970s, the WUTC actually prohibited natural gas utilities from connecting new customers to the system for a few years. The "hook-up ban" was lifted when additional Canadian gas supplies became available. However, these additional supplies came at much higher prices, and wholesale and retail gas prices soared between 1975 and 1981. As a result, local gas utilities in Washington were subject to two-tier wholesale pricing. Domestic gas was available in limited quantities at low prices, while Canadian gas was available to meet incremental demand, but only at much higher prices.

The limited availability of gas from domestic sources had several impacts on the Northwest. First, the pipeline capacity from the Southwest was not expanded, since there was no additional gas available. Second, pipeline capacity to the Canadian border *was* expanded. As a result of having much of our demand met with higher-cost Canadian gas, consumers in Washington paid gas prices that were higher than were paid in other parts of the United States until domestic prices were decontrolled in 1985. Higher than average gas prices, coupled with the lowest electric rates in the nation, meant that natural gas was slow to evolve as a residential and commercial heating fuel in the Pacific Northwest.

Natural Gas Industry Restructuring, 1985-1999

During the 1980s, both the federal and state regulatory authorities significantly restructured the natural gas industry regulatory framework. The federal action was directed at stimulating exploration and drilling, introducing additional competition into the industry and increasing the utilization of the gas pipeline network. The state actions were needed to accommodate the federal changes, and to facilitate large industrial consumers purchasing their gas in the marketplace opened by federal action.

Residential Natural Gas Prices 1970-1998



Source: Energy Information Administration, Historical Natural Gas Annual

Figure 1.3. Residential Natural Gas Prices in Washington vs. U.S. Average

The most important change enacted by FERC was unbundling of pipeline service, separating the business of gas supply from the business of operating the pipeline. Technically, pipeline companies could choose whether to remain in the merchant role, but the regulatory incentives were such that neither of the pipelines serving the state of Washington chose to do so. With the new structure, each of the local distribution companies entered into direct contracts with gas producers and/or marketers for their gas supply.

FERC also permitted industrial customers to bypass the local distribution utility by connecting directly to the interstate pipeline. This put pressure on the local distribution utilities and state regulators to reduce transportation rates for large users.

Washington utilities and the WUTC responded to FERC actions by allowing industrial customers to become “transportation” customers, meaning they could buy directly from producers and pay the utility only for delivery services. Some customers were offered special contracts reflecting site-specific bypass opportunities.

In 1996, the WUTC issued a Policy Statement suggesting changes to Purchased Gas Adjustments (PGAs) that had been in use for Washington gas utilities since the 1970s. Under PGAs, utilities are allowed to pass through actual gas acquisition costs to retail customers with periodic rate adjustments, subject to WUTC audit and review. Because utilities are not at risk for changes in the cost of gas, they earn no profit on the commodity portion of retail sales. Profit is earned solely on that portion of utility revenue related to delivery of the gas.

The Policy Statement proposed the use of financial incentives to utilities to minimize gas costs. Incentive Mechanisms were a response to the increasingly complex gas supply market which now offered hedging instruments, spot market purchases, capacity release transactions and “off-system” sales, in addition to the traditional long-term contracting. Instead of evaluating and auditing the prudence of each of thousands of transactions, the idea was to align the interests of ratepayers and the utility by rewarding the utility for achieving gas costs below an established market price benchmark.

Incentive Mechanisms were approved for two of the four LDCs, Puget Sound Energy and Avista, in 1998. These mechanisms provide the opportunity for utilities to earn a return on sales of commodity gas, if their gas acquisition costs are below a company-specific benchmark based on market indexes. Differences between actual acquisition costs and the benchmark are shared between utility shareholders and ratepayers. The effect of the Incentive Mechanisms approved in Washington is to encourage utilities to purchase gas commodity at market prices and then optimize the use of other resources such as pipeline capacity and gas storage in order to beat the benchmark.

Post-1985: Growing Demand for Natural Gas in the Northwest

The period from 1985 to 1999 saw dramatic reductions in natural gas prices at the sources of supply in Canada and the Rocky Mountains. Both the seismology used to find gas deposits and the technology used to drill for gas improved dramatically, leading to much lower costs to bring new fields into production. The two-tiered wholesale market in the Northwest evolved in the 1980s to reflect, in some years, a surplus of Canadian gas supplies and therefore lower prices for imported gas.

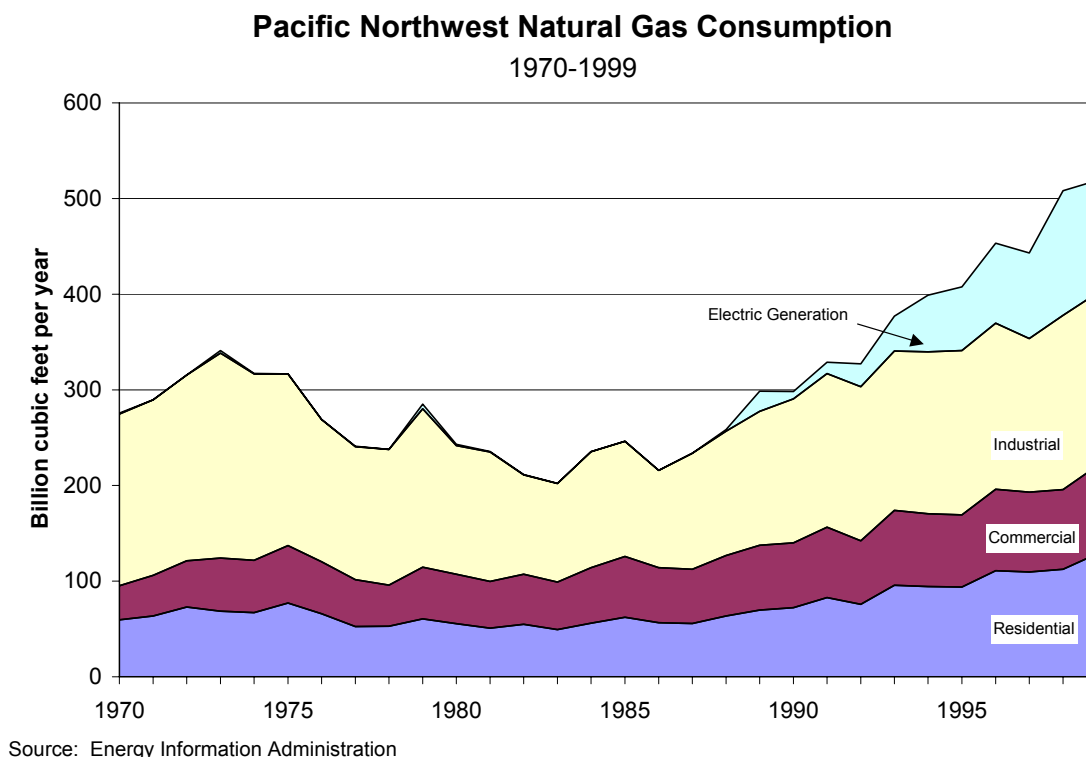


Figure 1.4. Pacific Northwest Natural Gas Consumption by End-Use Sector

These changes led to rapid decreases in the price of natural gas to end-use consumers, and accompanying increases in demand. The attractiveness of natural gas as a fuel was enhanced by higher electricity rates. Residential electricity prices in Washington rose 50% between 1979 and 1983 as the cost of large new coal and nuclear generating facilities were incorporated into retail rates. As a result of these changes, natural gas became the preferred fuel for residential heating – in the late 1990s, two-thirds of newly constructed homes in the state used natural gas for space or water heating.¹ Residential consumption of natural gas doubled between 1985 and 1999. Figure 1.4 depicts natural gas demand in Washington since 1970.

Residential customers, together with commercial and typically smaller industrial customers, make up the “core market”, or the market that is served by the natural gas distribution utilities. Growth in demand in these sectors has tended to occur roughly in proportion to increases in population and economy activity. Though yearly variations can occur due mainly to weather, growth in these sectors is gradual and relatively easy to plan for.

Industries use natural gas both for process heat and, in some cases, as a direct input to manufacturing of substances such as plastics and fertilizer. In the early years of natural gas availability, the vast majority was used by industrial processes, substituting for petroleum. Industrial use dropped off dramatically in the decade after the Arab oil embargo, as price-controlled domestic supplies of natural gas were unable to keep pace with demand. This meant that supplies of natural gas were unreliable for many industrial customers. Today, many industrial customers purchase their own supplies of natural gas and rely on the LDC system only for transportation services.

While the importance of historical industries, such as pulp and paper, has declined over time, and plants that continued to operate have become more efficient resulting in reduced demand for gas, Washington’s booming economy has led to significant new demand for natural gas in the industrial sector. Industrial natural gas demand grew by 50% between 1985 and 1999.

The Next Phase: Natural Gas for Power

Like gas-heated homes, the trend towards natural gas-fired generation came relatively late to the Northwest. The federal Public Utility Regulatory Policies Act of 1978 (PURPA) opened the door for independent ownership of power plants nationwide, many of which are fired by natural gas. However, the first natural gas power plants in the Northwest were utility-owned “peaking” units, simple-cycle gas turbines that were designed to be used a limited number of days per year to meet peak system demands. Spurred by PURPA guidelines, the early 1990s saw the construction of a number of 100-250 MW cogeneration plants, in which the heat generated by combustion is used to generate electricity and to power a “steam host” industrial process at the same time. Steam hosts have included oil refineries and forest products manufacturers.

In the 1990s, a fundamental shift occurred in the electric generation market. New combined cycle combustion turbine technology, coupled with extremely low commodity gas prices, made gas the nearly universal fuel of choice for electric generation. Gas plants were cheap to construct, cheap to operate, and environmentally were much preferred to coal or nuclear plants. Applications to construct over 2000 MW of new natural gas-fired electric generating capacity were approved by the Washington Energy Facility Site Evaluation Council (EFSEC) by 1996. While none of these plants had been built by 2001, a 248 MW plant was completed in 1997 and over 900 MW of gas-fired capacity came on line in Oregon and Idaho.

¹ Baseline energy efficiency study for Northwest Energy Efficiency Alliance by Ecotope, Inc.

In 1998, approximately 72% of the Pacific Northwest's electricity came from hydroelectric power, 4% from nuclear, and 16% from coal.² However, current plans call for the bulk of the region's growth in electricity demand to be met with natural gas-fired generating capacity. There are currently four major gas-fired generating plants under construction in the region (at Rathdrum, Idaho, and Klamath Falls, Boardman and Hermiston, Oregon), combining for nearly 1600 MW of generating capacity. Seven other plants have received site licenses, all in Washington. Table 1.1 lists all proposed natural gas fired generation facilities in the Northwest. Figure 1.5 shows the locations of the plants that are proposed for Washington.

If the plants currently under construction plus those already permitted come into service over the next four years, natural gas demand in the region would increase by 44% over 1999 levels, assuming the plants operate at 100% capacity factor. There are a number of additional projects that are currently in state permitting processes. The plants under construction, those currently permitted, and those for which potential site studies are underway constitute over 12,000 MW of generating capacity. If all were built, natural gas demand in the region would more than double. Figure 1.6 shows how regional natural gas demand would grow if all of the plants currently approved for construction and under active investigation were built.

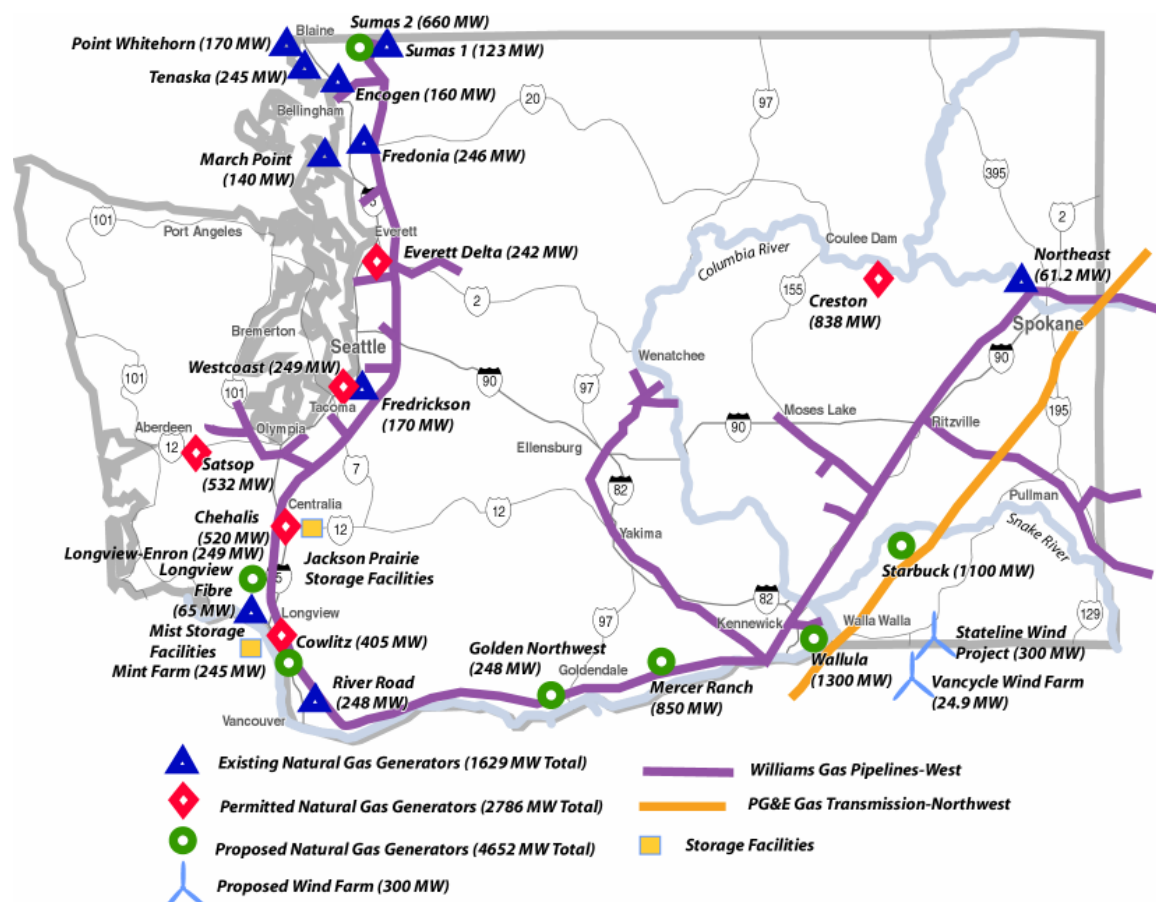


Figure 1.5. Existing and Proposed Natural Gas-Fired Power Plants in Washington

² Northwest Power Planning Council, Publication 98-22A, P. A-5

Table 1.1. Existing and Proposed Natural Gas Power Plants in Washington, Oregon and Idaho

Pipeline	State	Proponent/Owner	Facility name	Earliest Online Date	Capacity (MW)	Max. fuel use (MDth/day)	Status
GTN	OR	Portland General Electric Co.	Beaver	1977	534	80	Operating
GTN	WA	Avista Corp.	Northeast	1978	69	20	Operating
Northwest	WA	Puget Sound Energy	Frederickson	1981	178	51	Operating
Westcoast	WA	Puget Sound Energy	Point Whitehorn	1981	178	51	Operating
Northwest	WA	Puget Sound Energy	Fredonia	1984	247	71	Operating
Northwest	WA	March Point Associates	March Point	1991	140	21	Operating
Northwest	WA	Puget Sound Energy	Encogen	1993	160	27	Operating
Westcoast	WA	Sumas Cogeneration Co.	Sumas Energy	1993	123	21	Operating
Westcoast	WA	Tenaska Power Partners	Tenaska Washington	1994	245	41	Operating
GTN	ID	Avista Corp.	Rathdrum	1995	176	51	Operating
GTN	OR	Portland General Electric Co.	Coyote Springs Cogen. Project	1995	237	40	Operating
Northwest	WA	KVA Resources	Longview Fibre	1995	65	11	Operating
GTN	OR	PacifiCorp	Hermiston Generating Project	1996	469	70	Operating
Northwest	WA	Clark Public Utilities	River Road	1997	248	37	Operating
<i>Total Operating</i>					3,069	555	
GTN	ID	Avista Energy/Cogentrix	Rathdrum Power Project	2001	270	43	Construction
GTN	OR	City of Klamath Falls	Klamath Falls	2001	484	77	Construction
GTN	OR	Hermiston Power Partnership	Hermiston Power Project	2002	546	87	Construction
GTN	OR	Avista Power	Coyote Springs 2	2002	260	45	Construction
<i>Total Under Construction</i>					1,560	252	
Northwest	WA	FPL Energy	Everett Delta	2002	242	39	Permitted
Northwest	WA	Westcoast/EPCOR	Frederickson	2002	249	40	Permitted
Northwest	WA	Weyerhaeuser Co.	Cowlitz Cogeneration Project	2002	310	50	Permitted
Northwest	WA	Tractebel Power, Inc.	Chehalis Generation Facility	2002	520	83	Permitted
Northwest	WA	Energy Northwest	Satsop Combustion Turbine Project	2003	532	85	Permitted
Northwest	WA	Avista	Mint Farm	2004	245	39	Proposed
GTN	WA	Northwest Power Enterprises	Northwest Regional Power Facility	2003	838	134	Permitted
<i>Total Permitted</i>					2,936	470	
Northwest	WA	Enron	Longview Project	2003	249	40	Proposed
GTN	OR	PG&E National Energy Group	Umatilla Generating Project 1 & 2	2003	550	88	Proposed
Westcoast	WA	National Energy Systems Co.	Sumas 2 Generation Facility	2003	660	106	Proposed
Northwest	WA	Avista	Mint Farm	2004	245	39	Proposed
Northwest	WA	Goldendale Aluminum/NESCO	Goldendale	2004	248	40	Proposed
Northwest	ID	Ida-West Energy Co.	Garnet Energy Facility	2004	250	40	Proposed
GTN	WA	Northwest Power Enterprises	Starbuck Power Project	2004	1,100	176	Proposed
Northwest	WA	Cogentrix Energy	Mercer Ranch Generation Project	2005	850	136	Proposed
GTN	WA	Newport Northwest LLC	Wallula	2004	1,300	208	Proposed
Westcoast	WA	BP	BP Cherry Point	2004	600	96	Proposed
Northwest	WA	TransAlta	Centralia	2004	248	40	Proposed
GTN	OR	Cogentrix	Grizzly Power Generation Project	2005	980	157	Proposed
GTN	OR	Portland General Electric	Port Westward Generating Plant	2005	650	105	Proposed
GTN	OR	Westward Energy LLC	Summit/Westward Energy Project	2005	520	83	Proposed
<i>Total Proposed</i>					8,450	1,354	
<i>All Plants</i>					16,015	2,631	

Of course, many of these plants will never be built. Some plants have held site licenses for five years without taking any additional steps toward construction, while some newer plants that are not yet permitted appear to be quite likely to move forward. EFSEC signaled with its rejection of the Sumas Energy 2 application and its conditional approval of the Chehalis Generating Facility application that it will require demonstration of substantial public benefits as a condition for obtaining a site license. Ultimately, the region's electricity markets will only be able to support a certain amount of new capacity.

What that number is, however, depends on a variety of factors including hydroelectric conditions, growth in electricity demand, and the availability and price of new sources of natural gas. The Northwest Power Planning Council has estimated that 3000 MW of new generating capacity or load management would be needed in the Washington, Oregon, Idaho and Montana by 2003 in order to return to historical levels of planning reserve.³ The Energy Information Administration projects that over 1000 MW of new generating capacity will be added each year in the Northwest Power Pool area, which includes Utah and parts of Wyoming and Nevada in addition to the four Northwest states, between now and 2020.⁴ Washington, Oregon and Idaho's share of these projections would be 500-600 MW per year, or more than 5000 MW of new power plants by 2010. This level of construction would add 25-30 Billion Cubic Feet (BCF) of new natural gas demand each year and result in 8% annual growth in gas demand, roughly double the rate the industry has experienced in recent years.

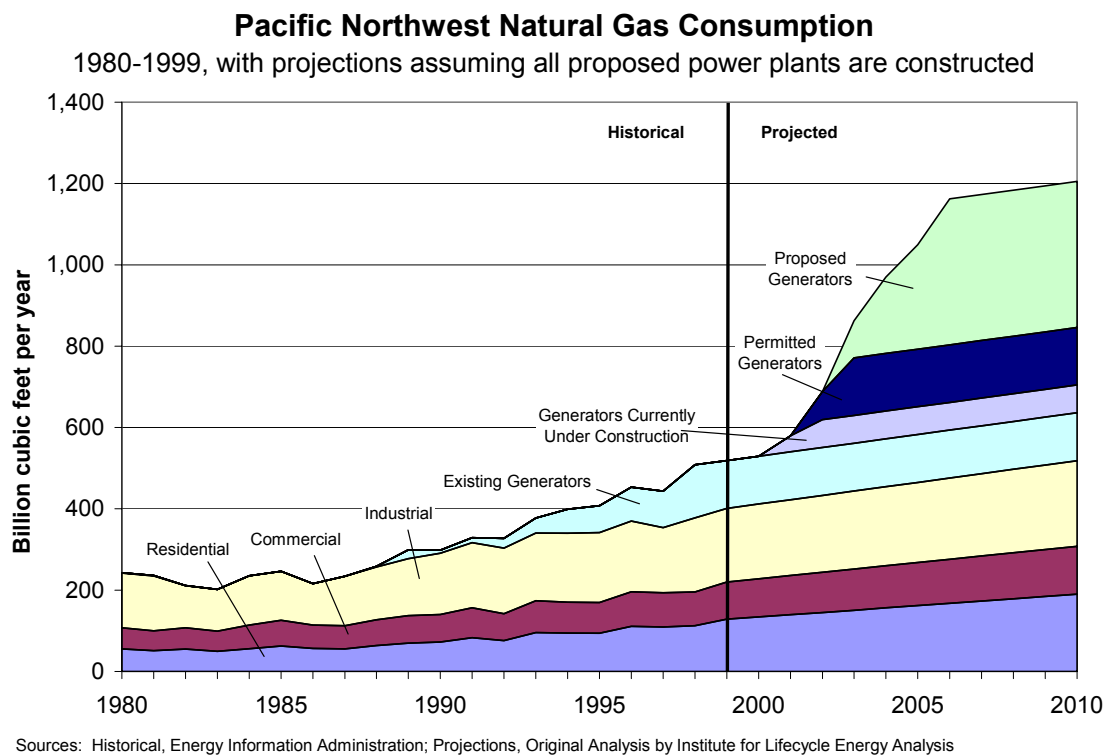


Figure 1.6. Past and Potential Natural Gas Consumption in the Pacific Northwest

³ Northwest Power Planning Council, *Northwest Power Supply Adequacy/Reliability Study Phase I Report*, Paper Number 2000-4, March 6, 2000

⁴ Energy Information Administration, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001), December, 2000

Table 1.2. Proposed Natural Gas-Fired Generating Capacity, WSCC Region (Megawatts)

	Under Construction	Permitted	In Permitting Process	Proposed	<i>Total</i>
Arizona	1,640	3,620	6,085	5,530	<i>16,875</i>
California	4,450	1,270	7,884	5,815	<i>19,419</i>
Canada - Alberta	1,495	-	750	318	<i>2,563</i>
Canada - British Columbia	340	265	50	50	<i>705</i>
Colorado	611	379	400	-	<i>1,390</i>
Idaho	270	-	-	250	<i>520</i>
Mexico - Baja California	640	750	-	297	<i>1,687</i>
Montana	-	-	22	2,660	<i>2,682</i>
Nevada	492	-	-	6,420	<i>6,912</i>
New Mexico	132	-	690	-	<i>822</i>
Oregon	1,120	280	649	25	<i>2,074</i>
Utah	-	-	-	-	<i>-</i>
Washington	249	2,533	3,060	1,197	<i>7,039</i>
Wyoming	172	-	-	-	<i>172</i>
Total WSCC	11,611	9,097	19,590	22,562	62,860

Source: California Energy Commission

Implications

Whether this level of construction presents problems for the industry depends crucially on the timing of both the new power plants coming on line and additions to the region's ability to deliver low-priced natural gas. If new power plants are added slowly, and if pipeline expansions both domestically and from producing fields in Canada precede or accompany the interconnections of new plants, and if new gas fields are brought on line at a reasonable cost, then increased gas demand from the new power plants will be accommodated smoothly with minimal disruption to existing customers.

It is far from certain, however, that all of the necessary events will occur in the proper sequence. If pipeline expansions are mistimed so that substantial new demand is added to the system without concomitant increases in deliverability, supply pressures could result in additional temporary price spikes of the kind seen in 2000-2001. These kinds of price spikes can be particularly damaging to consumers, because they are difficult to predict and are of uncertain duration, and are thus extremely difficult to plan for. If discoveries of new gas resources do not keep up with increased demand, or if new gas production is significantly more expensive than production at existing wells, the industry may experience substantial upward pressure on prices in the long-term. Utility Purchased Gas Adjustment mechanisms ensure that these price pressures are passed through to end-use gas customers.

Moreover, the Northwest will increasingly be subject to forces over which it has no control. Demand from new gas-fired power plants in California and other western states will place pressure on the Northwest's natural gas infrastructure even if the region doesn't build a single plant. Some 62,000 MW of natural gas power plants have been proposed in the Western Systems Coordinating Council (WSCC) region⁵; over 11,000 MW are already under construction. Increased ability to

⁵ The Western Systems Coordinating Council region encompasses all or part of the states of Arizona, Colorado, Idaho,

deliver gas to East Coast markets from producing areas in the Rocky Mountains and Canada means that new demand in the Midwest and Northeast will also have an impact on the Northwest. The convergence of the electricity and natural gas industries means that these effects will also be felt in electricity markets. California's disastrous electricity deregulation policies have already had a substantial impact on Northwest consumers of both electricity and natural gas.

Regardless of the pace and sequence at which the electric and natural gas infrastructures expand to meet growing regional energy needs, the longer term outlook for the region will be for the increased use of natural gas in generating electricity. Policies for improved resource utilization, ranging from higher energy conservation standards to more efficient direct-use of natural gas for space and water heating, could significantly mitigate the region's energy cost exposure. Even with the movement towards greater use of natural gas by residential and small commercial customers, the majority of the region's residential and commercial space and water heating requirements are still met using electricity as the delivered fuel source, particularly outside major urban areas. As a result, the opportunity still exists to reduce electricity demand through conversion of residences and commercial facilities to the direct use natural gas to meet space and water heating needs. Energy conservation and direct use of natural gas would reduce the need for large-scale gas-fired generation development and reduce or defer the requirement for major natural gas and electric infrastructure investments.

Many of these issues are discussed in more detail in later sections, and potential policy responses are presented in the concluding section.

Montana, Nevada, New Mexico, Utah, Wyoming, California, Oregon, and Washington, in addition to the Canadian provinces of British Columbia and Alberta, and a small part of northwestern Mexico.

Section 2. The Events of 2000 and Early 2001

The events of the second half of 2000 and the first part of 2001 represent a substantial departure from past expectations of natural gas and electricity markets. The extreme consequences from these events raise a number of important questions about the appropriateness of existing regulatory policies and company strategies. This section of the report analyzes these events, posits some partial explanations for the behavior of natural gas markets, and draws some inferences about how these events might change our expectations for the future.

The events began with sharp increases in both electricity and natural gas prices beginning in May of 2000. Electricity prices spiked to record levels during late June, and experienced a number of sustained periods of high prices throughout the summer. Natural gas prices were substantially higher throughout the summer as well. Both electricity and natural gas prices rose to new highs during November and December of 2000.⁶ Events in these two markets were clearly interrelated; electricity and natural gas are competing fuels for a number of end uses, and the greatly increased use of natural gas for electric generation during this period caused turmoil in electricity markets to infect natural gas markets as well.

At the retail end, three of Washington's natural gas utilities implemented an unprecedented second wave of price increases in January that will lead to most customers facing gas bills that are 50% to 90% higher than they paid a year earlier.⁷ Electric utilities caught short of power by dry hydroelectric conditions imposed temporary surcharges as high as 58% on electric rates to recover power purchased at extremely high prices.⁸ Several industries have curtailed production due to high utility costs for both gas and electricity⁹, and several that were exposed to market electricity prices began operating diesel emergency generators on a continuous basis in December.

Years of Plenty, 1992-1999

The seeds of this situation date back to the early 1990s, when the West Coast was awash in cheap energy. Wholesale gas prices dropped as low as \$1 per million British thermal units (MMBtu), and wholesale electricity prices ranged between \$10 and \$20 per megawatt-hour (MWh) through 1997. Depressed gas prices led to limited gas exploration in the U.S. Rocky Mountain areas, and slower growth in gas drilling in Canada.

⁶ In 1980, Canadian border wholesale gas reached \$5.04 per million BTU; that price was not reached again on a sustained basis until November, 2000, when the price got as high as \$40/MMBtu. During the month of December, the price ranged from \$11 to \$50 per MMBtu. Spot electricity prices peaked at \$3,100 per MWh on December 11, and averaged over \$400 per MWh for the month.

⁷ All of the state's gas utilities raised rates during the late summer. All but one did so again in the winter. One gas utility is a notable exception; Northwest Natural Gas Company, facing a different set of regulatory policies because the bulk of its customers are in Oregon, locked in gas prices at less than \$5.00/MMBtu, and did not submit a second price increase request.

⁸ At least six publicly-owned utilities in Washington imposed rate increases or surcharges in late 2000 or early 2001, ranging from 21% by Grays Harbor PUD to 58% by Tacoma Power. Rates were also increased by Seattle City Light and Cowlitz, Clark and Snohomish PUDs. Among IOUs, Avista requested and received permission to defer increased wholesale power costs for possible future recovery, but Puget Sound Energy and Pacific Power are covered by long-term rate plans which preclude increased rates to most consumers unless financial hardship can be demonstrated.

⁹ Cascade Natural Gas reports sharp reductions in consumption by their pulp and paper customers. A number of customers have installed diesel generators which cost less to operate than market purchases of electricity. Most of the region's aluminum producers have opted to reduce operations as their electricity is more valuable than the aluminum it could produce.

In addition, low electricity prices and uncertain regulatory incentives meant relatively little new power plant construction both in the Northwest and in California. California's 1996 deregulation law required utilities to divest their oil- and gas-fired power plants. Companies that wished to enter the California electricity market could purchase existing generators at prices that were low compared to the cost of permitting and constructing new capacity. Utilities eliminated their resource planning activities and, under the regulatory system set up by the legislature, began to purchase the vast majority of the power they needed in hourly markets on the state-sanctioned California Power Exchange.

In the Northwest, surplus hydropower was available for less than \$20 per MWh on the nascent wholesale electricity market, leading to pressures to deregulate retail electricity markets. A panel convened by the governors of Washington, Oregon, Idaho and Montana recommended opening retail markets to competition, and advised the Bonneville Power Administration (BPA) to avoid building new generation. Utilities were extremely reluctant to invest in new generating capacity with uncertainty about which retail loads they would serve in the future. While a number of independent power projects were permitted, few could get financing due to low wholesale prices.

By 1997, the economy was heating up, and electric loads were increasing rapidly. The West Coast electricity surplus was shrinking, but the impact was masked by favorable weather and hydroelectric conditions. In 1998, extremely wet conditions kept electricity prices low and allowed the Pacific Northwest to export electricity to California equivalent to about 5 times the annual usage of Seattle. These exports meant that California's older, less-efficient gas-fired generators remained largely idle. In 1999, California experienced the mildest weather in over 30 years. The mild temperatures meant low air-conditioning loads, low irrigation pumping loads, and, again, little need to operate the older gas-fired generators.

The Beginnings of a Crisis

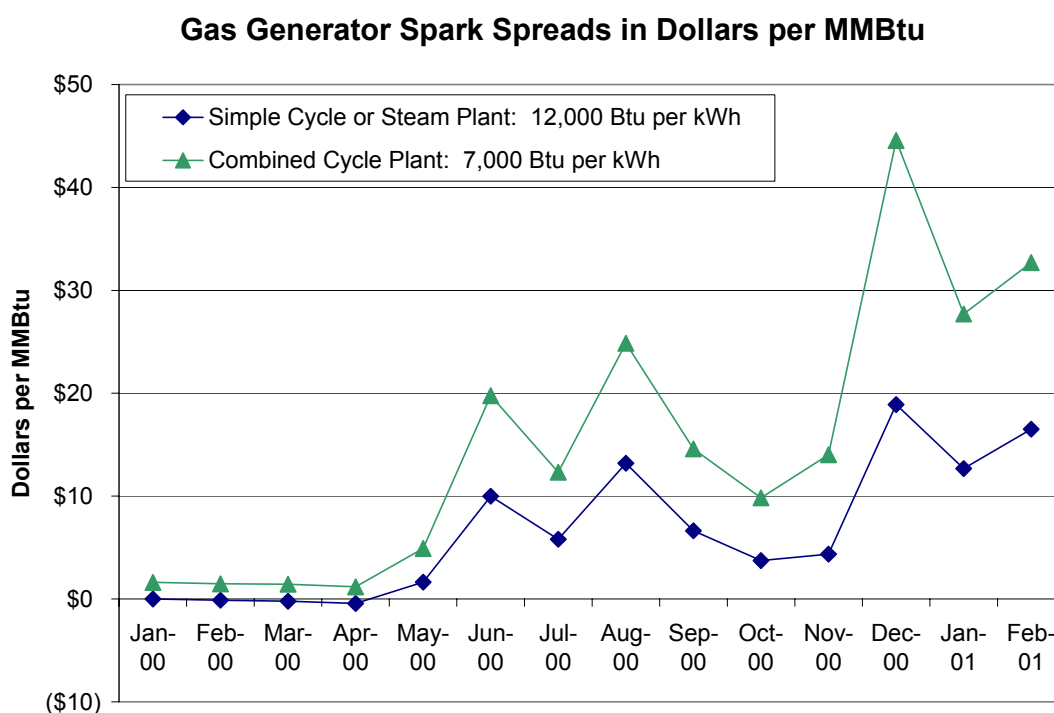
All of this came to a sudden end in the summer of 2000. Sustained hot weather in California meant high levels of demand for electricity. Increased air conditioning saturation in the Pacific Northwest (mostly in retail, office and computer-oriented settings) meant rapid load growth in summer usage in this region. Combined with drier than average hydroelectric conditions, this meant substantially reduced hydropower exports from the Northwest to California. For the first time in a decade, California's older, inefficient gas-fired generating plants were called upon to operate on a continuous basis. The legal, institutional, physical and fiscal infrastructures all reached their limits simultaneously.

First, the gas production and delivery system strained to serve the simultaneous loads of all gas consumers. While gas deliverability had increased, it had not increased sufficiently to serve both growing demand outside the utility sector plus resumed demand within the utility sector, and other customers had become accustomed to using the idle gas capacity. Wholesale gas prices began to rise in May, and stayed above \$3 per MMBtu through August. This was compounded by an explosion on the El Paso natural gas pipeline in New Mexico, taking a significant amount of transmission capacity to California out of service. While electric generating demand for gas siphoned away gas supplies that were constrained by the pipeline explosion, the resultant rise in wholesale gas prices led to lower than normal levels of gas in underground storage leading into the

winter of 2000-2001.¹⁰ This rise in fuel costs meant that the cost of generating electricity increased from \$20-30 per MWh to \$60 per MWh in a month due solely to increased fuel costs.

However, power prices spiked much higher than what would be expected due to natural gas prices alone. Daily peak period prices at the Mid-Columbia trading hub reached \$672 per MWh on June 28 after a string of unplanned outages among major Northwest generators, and stayed above \$100 for most of the summer. Prices were even higher in California. A variety of reasons have been postulated for the sudden rise in power prices, including accusations of market manipulation and price gouging on the part of power generators. A full treatment of the conditions in western power markets in 2000 is beyond the scope of this report. However, it is safe to conclude that high margins in the wholesale electricity market created severe upward pressure on natural gas prices.

These phenomena are illustrated in the following series of charts and tables. Figure 2.1 demonstrates how high electricity prices allowed operators of natural gas power plants to pay very high prices for natural gas and still operate profitably. The chart shows the “spark spread”, or the difference in the cost of energy in Northwest electricity and natural gas markets, for two types of power plants.



Sources: Dow Jones Mid-Columbia Index, Natural Gas Week

Figure 2.1. Northwest Gas Generator Spark Spreads, 1/00 – 2/01 (Sumas and Mid-Columbia trading hubs)

A spark spread represents the margin available to the operator of a power plant, given current natural gas and electricity prices, and a plant-specific heat rate.¹¹ It represents the maximum a power plant operator would be able to pay above the actual price of gas and still make a profit.

¹⁰ The Pacific Northwest was a notable exception, as natural gas storage facilities such as Jackson Prairie and Mist are relied upon to meet maximum peak demands and hence were refilled on a normal schedule.

¹¹ A heat rate is a measure of a power plant’s efficiency at turning energy inputs such as natural gas into electricity.

Spark spreads are thus useful tools for understanding the extent of the price pressure placed on natural gas markets by the extreme events in electricity markets.

For example, natural gas was available for around \$2.50 per MMBtu during the first four months of 2000, while electricity was selling for around \$27 per MWh. At these prices, a low-efficiency natural gas plant, such as a peaking unit or an older, steam-fired power plant, would not quite break even on an operating basis. When non-fuel operating costs are added, plants of this nature would have been unlikely to operate during those months. A more efficient, combined cycle power plant would have realized an operating profit of between \$1.00 and \$1.50 per MMBtu of gas burned, because it can make more electricity with the same amount of natural gas.¹²

The picture changed dramatically in May. Rising power prices led to spark spreads of higher than \$10 per MMBtu in June even for inefficient plants, and up to \$25 in August for efficient units. That means that if non-fuel operating costs were as high as \$10 per MWh produced, a combined cycle plant would have been able to pay up to \$23 per MMBtu for natural gas in August and still break even. Wholesale natural gas prices averaged \$3.15 per MMBtu for that month.

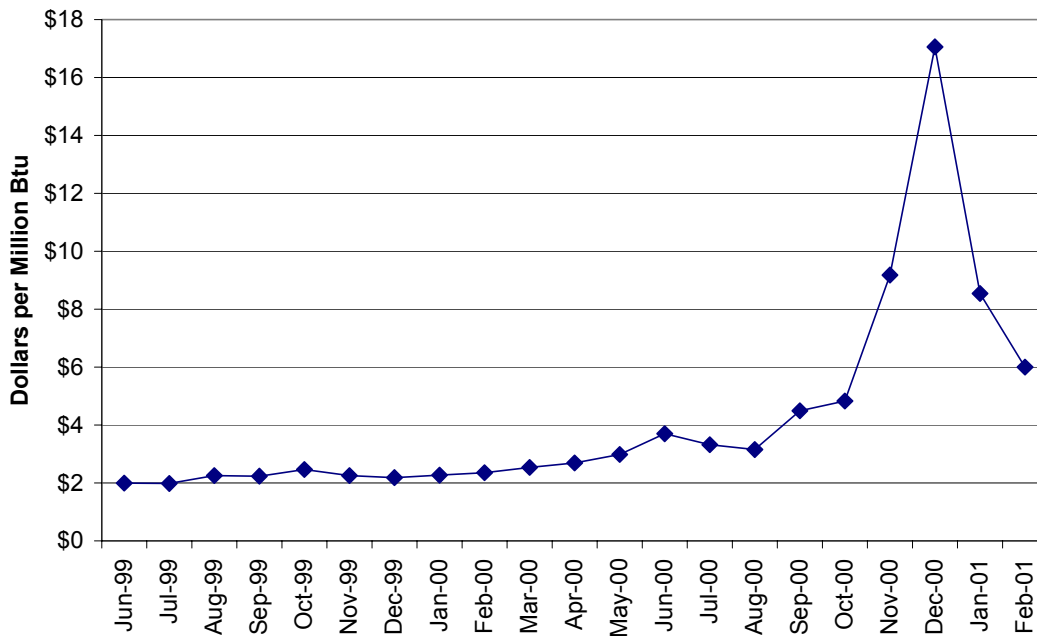
Figure 2.2 shows monthly average wholesale natural gas prices at the Sumas trading hub from June, 1999 through February, 2001. Given the margins available to holders of natural gas-fired generating capacity, it is unsurprising that gas prices followed power prices upward. What *is* surprising is that gas prices didn't rise sooner, and faster. The natural gas delivery system did show signs of strain in the form of prices that rose in May and stayed above historical levels for the rest of the year. However, until the beginning of the peak winter season in late November, it appears that the major constraint was the capacity to turn natural gas into a higher-valued product, electricity. Holders of that capacity were richly rewarded in the marketplace.

Pollution control costs in Southern California may have been a contributing factor. A decade ago, the South Coast Air Quality Management District adopted strict regulations on the amount of pollution that can be emitted in the Los Angeles area. One of their programs, known as RECLAIM, limits the amount of nitrogen oxides (NOx) that any given industrial facility or power plant operator can emit. The pollution rights are tradable, and between 1992 and 1999, depressed demand for operating gas-fired power plants meant that the rights carried a very low value. In 1998, a pound of NOx emissions carried a price of about \$1.00 or less; in 1999, with reduced hydroelectric exports from the Northwest meaning higher electric generation in California, that price rose to \$8.00. By August, 2000, the price of RECLAIM credits had risen to over \$50/lb.¹³ At this price, even the "best" gas-fired power plants in Los Angeles faced a \$50 per MWh cost for pollution rights, and the "worst" plants faced a cost five times as large. This may help explain why high power prices did not pull natural gas prices to historical levels until later in the year.

¹² For simplicity, these spark spreads were calculated using monthly average market prices at the Sumas (natural gas) and Mid-Columbia (electricity) trading hubs. Actual operating decisions for swing plants are based on daily or even hourly spreads that are specific to the power plant location.

¹³ NOx credits are traded by in a real-time auction market operated by the brokerage firm Cantor Fitzgerald; some bilateral trades are made outside the auction market, but these are typically for multi-year periods where some price averaging takes place.

Natural Gas Spot Market Prices at Sumas, WA



Sources: Natural Gas Week, Energy Online

Figure 2.2. Wholesale Natural Gas Prices, 6/99 – 2/01

While high natural gas prices were little bother for generators selling into inflated electricity markets, natural gas distribution utilities like Puget Sound Energy, Avista Corporation, and Cascade Natural Gas were forced to implement major rate increases in late 1999, August or September, 2000, and January, 2001, based on Purchased Gas Adjustment mechanisms described in the previous section. These companies typically purchase gas at monthly index prices, i.e., prices based on surveys of gas transactions made at major market centers. Northwest Natural, another natural gas utility that has the majority of its customers in Oregon, pursued a different strategy, locking in its winter gas supplies through forward purchases before wholesale prices began to spike. As a result, Northwest Natural's rates did not go up in January. The table below shows how the average residential natural gas bill has changed since January, 1999. All gas users, including industries that purchase their own gas, have faced huge increases in their gas costs since May, 2000.

Table 2.1. Average Monthly Household Natural Gas Bill for Washington Utilities

	Customers	Jan 1999	Jan 2000	Sep 2000	Jan 2001
Puget Sound Energy	591,000	\$41	\$47	\$61	\$77
Cascade Natural Gas	145,000	\$37	\$41	\$45	\$60
Avista	119,000	\$27	\$31	\$42	\$55
Northwest Natural Gas	38,000	\$32	\$36	\$49	\$49

It is instructive to consider how different regulatory policies in Washington and Oregon affected company purchasing strategies during this period. Under Washington's PGA and incentive mechanisms, company risk is minimized by purchasing the majority of gas supply at monthly market index prices. In Oregon, returns are based on differences between actual prices and year-ahead forecasts; companies can minimize their risk by hedging or locking prices at the time of the

forecast. Northwest Natural, with most of its customers in Oregon, pursued this strategy, and customers in Clark County were spared a January, 2001 rate increase.

Each of these strategies carries its own set of risks for retail customers. Oregon policies result in retail prices that change less frequently and are therefore more predictable, but not necessarily lower. If winter gas prices had been lower than September forecasts, Northwest Natural customers would have ended up paying more than customers of other utilities. Moreover, suppliers generally require a premium to lock in prices in advance, so this strategy may result in somewhat higher costs in the long run. Washington policies lead to greater customer exposure to market volatility because of the regulatory risks associated with pursuing strategies other than purchasing at monthly market indexes. Even if Washington utilities had anticipated November's higher prices, acting on that expectation through forward purchases would expose the companies to a degree of risk that may not be commensurate with potential returns.

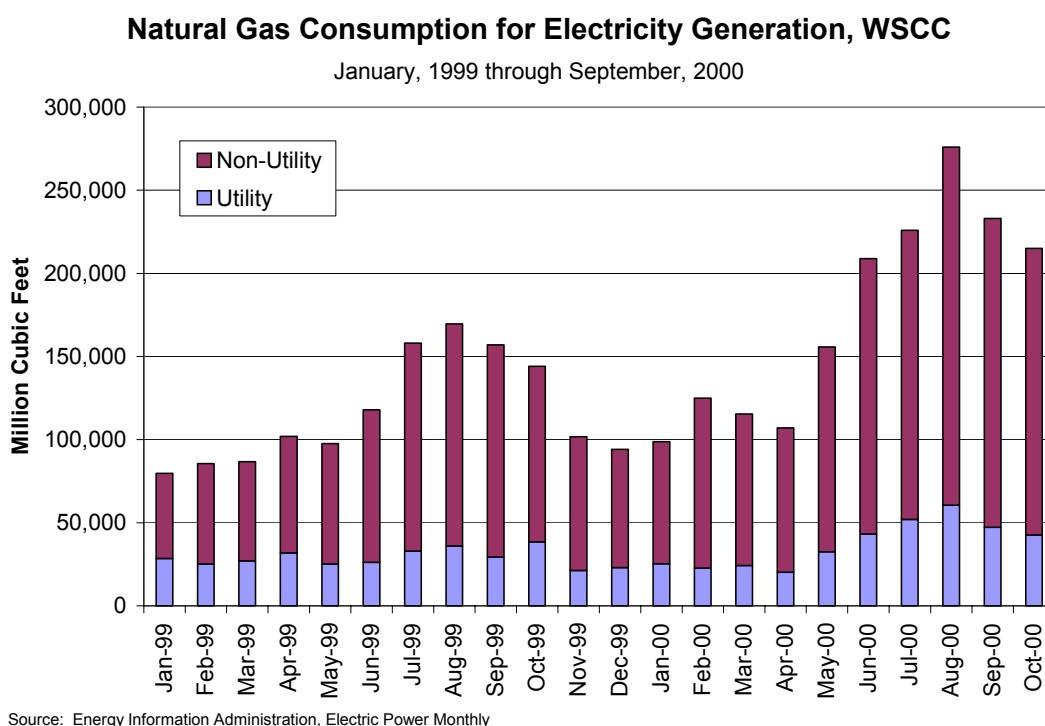


Figure 2.3. 1999-2000 Natural Gas Consumption for Electricity Generation, WSCC Region

As dry conditions continued in the Northwest, power exports from the Northwest dried up, and the entire West Coast continued to rely on gas-generated electricity to a degree not experienced in at least two decades. Figure 2.3 shows that natural gas used for electric generation was significantly higher in 2000 compared with 1999 in the WSCC region. Table 2.2 shows a state-by-state breakdown of the increase. While California accounts for around three-fourths of gas consumption for electricity generation in the WSCC region, gas consumption was higher in 2000 in nearly every western state. The total increase from January to September was some 500 billion cubic feet. When final 2000 numbers are in, the *increase* in gas consumption for electric generation during 2000 is likely to exceed the total gas consumption by all residential consumers in the western United States for the year.¹⁴ In Washington, the 142% increase was the highest in the region, though from a low base.

¹⁴ Total residential gas consumption for the Pacific Contiguous states was 678 billion cubic feet. Through September,

Table 2.2. Natural Gas Consumed for Electricity Generation, WSCC Region

	Natural Gas Consumption for Electricity Generation, January to October (Million cubic feet)		
	2000	1999	Increase
Arizona	78,965	48,692	62%
Colorado	61,865	48,244	28%
Idaho	3,411	3,128	9%
Montana	177	407	-57%
Nevada	111,506	82,027	36%
New Mexico	48,422	41,167	18%
Utah	6,986	4,094	71%
Wyoming	5,763	3,760	53%
California	1,282,582	874,609	47%
Oregon	76,581	57,003	34%
Washington	84,366	34,791	142%
<i>Total WSCC</i>	<i>1,760,624</i>	<i>1,197,922</i>	<i>47%</i>

Source: Energy Information Administration, Electric Power Monthly

Table 2.3. Electricity Generation by Major Fuel Type, WSCC Region

	Generation by Fuel Type, January to October (GWh)		
	2000	1999	Increase
Coal	205,221	184,626	11%
Nuclear	62,061	56,675	10%
Hydroelectric	165,944	192,051	-14%
Natural Gas	138,505	99,210	40%
Other	32,426	34,073	-5%
<i>Total Generation</i>	<i>604,157</i>	<i>566,635</i>	<i>7%</i>

Source: Energy Information Administration, Electric Power Monthly

Not only was hydroelectric production lower in 2000 than in 1999, but electricity demand was up by 7% during the first nine months of 2000. Natural gas power plants were called upon to make up the difference, resulting in natural gas consumption for electricity generation that was running 50% higher than the previous year. On an annualized basis, this is the equivalent of instantly adding nearly 6000 MW of natural gas-fired generating capacity to the western system.

Market Meltdown

By November, the combination of high prices, reduced levels of storage inventory, and heavy reliance on gas for electric generation created challenges of monumental proportions. Many power plants in Southern California were shut out of the market entirely for lack of NOx pollution credits. Spot market electric prices again soared to levels once thought unimaginable. One Southern

the increase in gas usage in 2000 compared with 1999 for electric generation was over 500 billion cubic feet, and when year-end figures are complete, it is highly likely that the total will exceed total residential usage.

California utility did a technical study of one of its power plants, and determined that raising the output from 70% to 100% of rated capacity caused such high increases in pollution emissions that prices would have to reach \$1000 per MWh before it was cost-effective to operate at full output.¹⁵

And in December, conditions got even more challenging. Prior to December, the rest of the nation had not experienced the same challenges as the West Coast. Wholesale gas costs had increased, but remained significantly lower than in the west. In December, however, temperatures were well below average across the country,¹⁶ creating sharp increases in wholesale gas prices. Gas storage levels were also well below average, particularly in California, where they were about 19% below typical levels. Nationwide, in response to cold weather and depleted storage inventories, wholesale gas costs reached \$10 per MMBtu by mid-December, five times the level a year earlier.¹⁷

The problems were magnified on the West Coast. Hydroelectricity generation reached critically low levels in California and the Northwest, making gas-fired generation more important than ever. Gas demand soared as cold weather set in, placing major strains on the California delivery system. Pipeline capacity into California and from the California border to major markets within the state became severely constrained, leading to huge differentials in the price of natural gas at various locations in the west. Pipeline capacity from producing fields in the Rocky Mountains and Canada was particularly constrained, partly due to the fact that El Paso was still operating at reduced capacity due to the New Mexico explosion. While wholesale gas prices in the Rocky Mountains and Alberta were frequently less than one-half the levels in the Northwest and California, pipeline capacity limitations meant that local market prices for natural gas would soar.

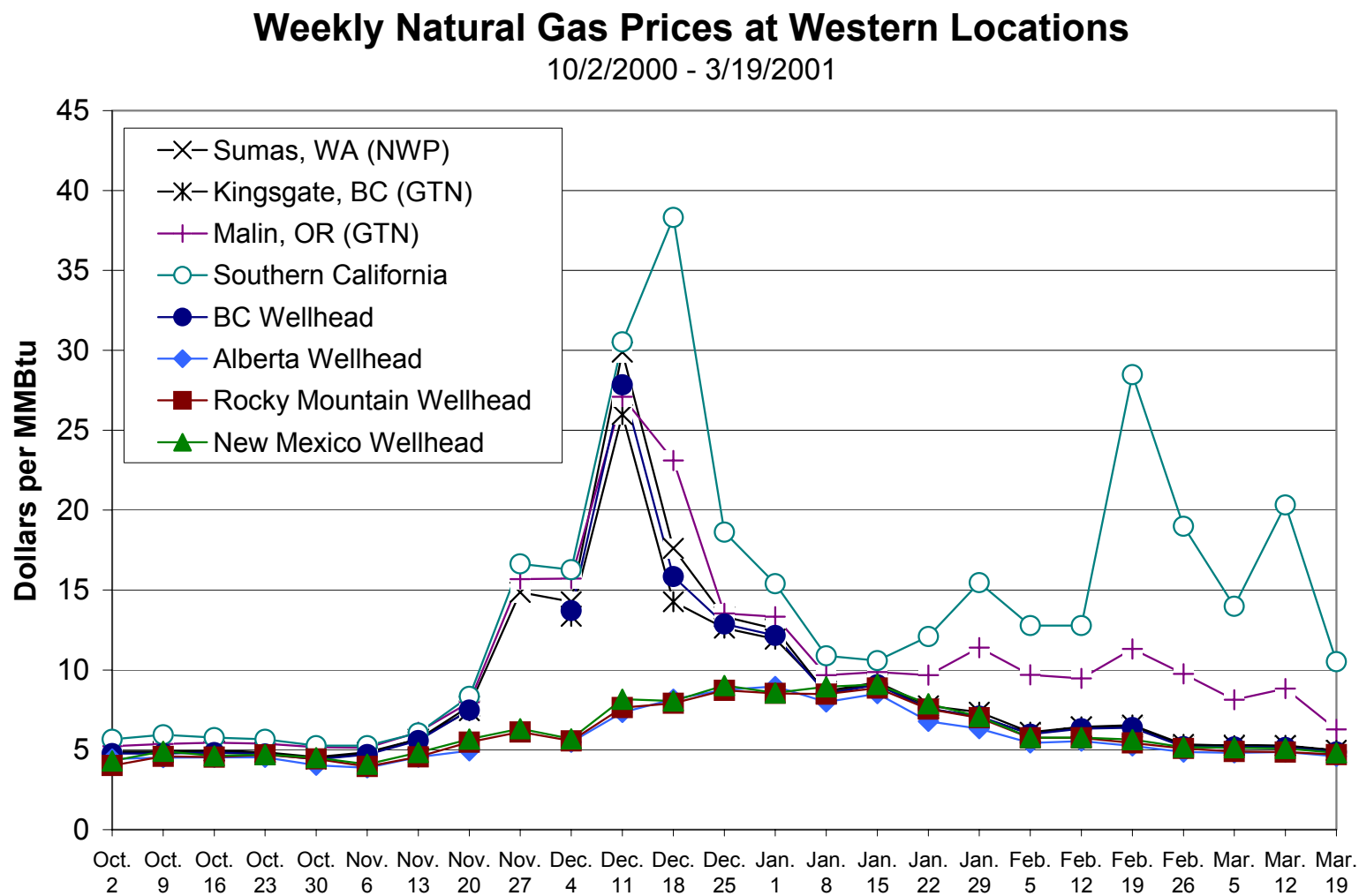
These events are illustrated in Figure 2.4 below. This chart presents weekly spot prices at various locations in the West for October, 2000 through March, 2001. The apex was reached on the weekend of December 9, 2000. The natural gas delivery system was stressed to the limit, and unit outages and extremely low water in Northwest rivers meant that little surplus generating capacity was available. Cold weather was forecast, promising even higher demands for gas and electricity. Mid-Columbia spot prices for electricity peaked at \$3,100 per MWh on December 11. Spot prices for natural gas reached a peak of \$52 per MMBtu at the Sumas hub, and averaged \$30 per MMBtu for the entire week.

This price movement was mirrored for other trading points in the west, including the Kingsgate, BC, interconnection of the TransCanada and GTN pipelines, and Malin, OR, near the California-Oregon border. Prices spiked as high as \$59 in Southern California – some twenty times higher than just a year earlier, and averaged nearly \$40 for the week of December 18.

¹⁵ Personal conversation with Fred Fletcher, Assistant General Manager, Burbank Water and Power, Nov., 2000.

¹⁶ According to the U.S. Energy Information Administration Natural Gas Market Report, temperatures in December averaged almost 8 degrees below normal on a nationwide basis.

¹⁷ Reuters Commodities and Energy service.



Source: Natural Gas Week

Figure 2.4. Weekly Natural Gas Prices at Western Locations

It is also interesting to note where prices *didn't* spike. Wellhead prices at producing areas in the Rockies and Alberta did rise in November and December, but peaked at around \$9 per MMBtu, in line with natural gas prices in the rest of the country but well below peak prices paid in West Coast markets. This implies price differences, referred to as “basis differentials”, of up to \$30 per MMBtu on major pipelines that deliver gas to the West Coast. Both major pipelines serving the Northwest were affected; high basis differentials between wellhead prices in Alberta and prices at Kingsgate indicate that the British Columbia leg of the TransCanada system became constrained during November and December, while prices on Northwest Pipeline diverged on either side of the Kemmerer Corridor in Wyoming.

Differentials between Sumas and Rocky Mountain hubs may have been exacerbated by operational flow orders (OFOs) called by Northwest Pipeline. As a bi-directional pipeline, Northwest relies on a certain amount of displacement capacity to achieve maximum contractual flows. That is, gas is shipped in both directions to achieve supply and market balance. If transactions that are desired by the market would result in too much flow in one direction, OFOs become necessary to keep the pipeline balanced. These OFOs required shippers with certain contractual obligations to purchase gas at points north of the Kemmerer constraint and resell it south of the constraint, at losses of up to \$30 per MMBtu. This was the first time in its history that Northwest Pipeline had to implement this type of “must flow” OFO. This issue is described in greater detail in the next section.

In British Columbia, by contrast, wellhead prices did rise in line with prices being paid downstream, and basis differentials remained small. While pipeline capacity from the Rockies to the West Coast was constraining, capacity on the Westcoast pipeline from BC producing areas to Sumas was not. [Some market participants have reported that basis differentials similar to other major pipelines did develop in daily markets and in the monthly indexes on which the price of much of the natural gas consumed in Washington is based. This was not evident in the weekly price data analyzed for this report.]

More recently, gas prices have again spiked at California locations, although prices in the rest of the West have remained in line with the rest of the country. Continued constraints on interstate pipelines into California and to major markets in the state may have been exacerbated by the credit crunch faced by California utilities. A number of gas suppliers have become reluctant to sell to California utilities without some assurance that they will be repaid, and have charged higher prices to California utilities to reflect this increased risk. Pacific Gas & Electric has reportedly had to rely on storage withdrawals to meet some of its core customer demand because of difficulty arranging for supplies. This phenomenon has not affected prices at other market centers in the West; on the contrary, less gas being delivered to California might mean increased supply at other locations, resulting in downward pressure on prices.

It is important to note that the events described here have not resulted in reduced reliability for small consumers of gas or electricity in the Northwest. While discount rate interruptible electric and natural gas customers have had their service shut off during peak hours under the terms of their interruptible contracts, those gas and electric customers in the Northwest who pay for firm service, including all core customers, have not suffered service interruptions.

The story is different in California, where rolling blackouts occurred on January 17 and 18, 2001 and again on March 19 and 20, and the California Independent System Operator implemented 32 straight days of “Stage 3” alerts due to insufficient generating resources. The precipitating event was a credit crunch brought on by regulatory policies that left California investor-owned utilities unable to recover billions of dollars in power purchases. These extraordinary events are unlikely to

repeat themselves in the Northwest, as none of the utilities in this region are exposed to market prices to anywhere near the same extent as California's IOUs. However, continued extreme dry conditions could lead to additional severe stress on the Northwest power system.

Implications

What does the future hold? Weather in December, 2000, did not reach anywhere near record cold levels in the Northwest, so the strain on the system could be much greater. The addition of a number of new, natural gas-fired power plants could strain the system even further if not accompanied by new infrastructure. One measure of industry expectations is the New York Mercantile Exchange market for natural gas futures. As of late February, natural gas futures were above \$5 per MMBtu for each of the next twelve months.¹⁸ Looking ahead two years, the Energy Information Administration projects that wholesale natural gas prices will range between \$4 and \$5 per MMBtu through the end of 2002.¹⁹ This is still more than double the price in effect at the beginning of the 2000. While electricity futures are very thinly traded and are thus unreliable indicators of future expectations, forward prices for electricity for the year were reported in the range of \$200 per MWh in testimony before the WUTC in early January²⁰, more than five-times the rate a year earlier.

The events of the last eight months have made clear that wholesale electricity and natural gas prices are subject to extreme price volatility. This may seem obvious now, but it is apparent that, until recently, the risks of price volatility were not well understood by policy-makers, regulators or even industry participants. While the extreme volatility experienced recently is probably an aberration, plans to greatly expand gas-fired electricity generation up and down the West Coast could well lead to further strains on natural gas markets. Coincident peak demands for natural gas and electricity mean that extreme price events are likely to affect both markets simultaneously.

This bears a number of implications for regional electricity and natural gas utility systems and for industrial customers purchasing their supplies directly. Electric utilities that were caught short in 2000 will likely pursue strategies that provide better insurance against future price volatility. Electric generating facilities that do not use natural gas will be more attractive as new energy options; these range from the environmentally desirable options such as wind and geothermal to more challenging conventional sources such as coal and nuclear. BPA announced in February, 2001, that it would seek to acquire up to 1000 MW of wind power, at least partially because of the hedge that fixed-priced wind power can provide against volatile natural gas prices. Energy efficiency investments are also more attractive than they have been in recent years. The Northwest Power Planning Council's Regional Technical Forum completed an analysis in January, 2001, showing that a sharply higher level of cost-effective investment is justified, and BPA announced in February that its conservation and renewables discount plan would begin several months earlier than planned.

Natural gas utilities in Washington are insulated from market price volatility, because the PGA mechanism allows for pass-through of volatile market purchases to retail customers. Three of the four utilities that serve Washington implemented rate increases in September, 2000, and again in January, 2001, due to rapidly escalating wholesale prices. Northwest Natural, facing a different set

¹⁸ New York Mercantile Exchange (NYMEX)

¹⁹ Energy Information Administration, *Short-Term Energy Outlook*, February 6, 2001.

²⁰ WUTC Docket UE-001952, Exhibit 25, and testimony of Matt Franz, Bill Gaines, Jim Lazar

of regulatory incentives because the vast majority of its customers are in Oregon, locked in prices ahead of time and avoided some of the rate increases. The different behavior of these companies illustrates the extent to which regulatory policy can influence company purchasing strategies. Under Washington's PGA incentive mechanism, company risk can be minimized by purchasing the majority of needed commodity at market-indexed prices. In Oregon, companies lock in prices based on year-ahead forecasts through hedging and longer term contracting. The question for policy-makers is whether existing regulatory policies governing cost recovery for utility wholesale market activities are still appropriate in light of new evidence about the risks of extreme price volatility. Do current policies align the utility's interest in avoiding risk with the customer's interest in lower natural gas prices? Do current policies encourage too much dependence on market indexes that are volatile and could potentially be subject to manipulation? Do they properly balance competing objectives of price stability and lower costs in times of extreme volatility?

The natural gas industry is responding to these events by firming up plans for expanding pipeline capacities and by drilling for natural gas at record rates. New gas supplies in the far north of Canada and Alaska may be brought on line. Plans are being developed to increase imports of liquefied natural gas from the Middle East to the East Coast. These plans are described in more detail in later sections. Depending on the outcome of the crash drilling program and the cost of building pipelines to Arctic gas sources, prices may eventually retreat to more familiar territory. Alternatively, adding substantial new demand to an already taxed system could result in prices that remain high for the foreseeable future.

The year has been a period of very challenging technical and economic conditions for both the gas and electric industries. System reliability has been tested in ways never before experienced – and in most cases, the tests proved the dependability and redundancy of both utility systems. However, the financial cost of soaring wholesale prices will be felt for many years to come.

Section 3. Natural Gas Pipelines Serving the Pacific Northwest

The Pacific Northwest is served by two interstate pipelines operated by the Northwest Pipeline Corporation and PG&E Gas Transmission, Northwest (GTN). These pipelines deliver natural gas from Canadian and domestic sources to customers throughout the Northwest and also to the Southwest and Rocky Mountain regions. Shippers, including local distribution companies, large industrial customers, and energy marketers, purchase capacity on the pipelines to deliver gas from particular suppliers and receipt points on the system to particular delivery points. Shippers can elect to purchase firm capacity, which will be available under all but emergency circumstances, or non-firm capacity, which can be recalled at the discretion of the pipeline company to meet the needs of customers with firm capacity. This section considers the nature of natural gas flows and pipeline operation, pipeline capacity, and expansion plans for each of the primary interstate pipelines.

The Evolution of Federal Pipeline Policy

Prior to FERC Orders 436, 500 and 636, and the implementation of the Wellhead Decontrol Act, all aspects of the natural gas market were regulated. FERC established prices for natural gas. Interstate pipelines purchased gas at the wellhead or from other pipelines and delivered that gas at regulated rates to local distribution companies (LDCs). The LDCs, in turn, distributed gas to industrial, commercial, and residential consumers at rates regulated by the states, which permitted pass-through of the interstate pipeline costs under Purchased Gas Adjustment mechanisms.

The passage of the Natural Gas Policy Act (NGPA) in 1978 provided for gradual deregulation of natural gas prices. In 1985, FERC issued Order No. 436, which established rules for pipelines to offer open access transportation service independent of their traditional natural gas commodity sales. In 1989, Congress passed the Wellhead Decontrol Act, which provided for the removal of all regulation from the gas commodity by 1993. The Wellhead Decontrol Act also directed FERC to regulate interstate pipeline capacity in a way that would “maximize the benefits of [wellhead] decontrol.”²¹

In Order No. 636, issued in April, 1992, FERC required pipelines to separate their sales of gas from their transportation service and to provide comparable transportation service to all shippers whether they purchase gas from the pipeline or another gas seller. Order No. 636 allowed firm holders of pipeline capacity to resell or release their capacity to other shippers and required pipelines to permit shippers to use flexible receipt and delivery points. The changes allowed shippers to purchase capacity from any number of firm capacity holders and to inject and deliver gas at points useful to the purchasing shipper, rather than the primary points in the original shipper’s contract.

As a result of these policy changes, competitive natural gas markets began to develop. New market centers facilitated the buying and selling of natural gas and, in 1990, the New York Mercantile Exchange (NYMEX) established a futures market using the Henry Hub market center in Louisiana as the physical delivery point. Shippers and marketers began to use the capacity release mechanism as an alternative to obtaining transportation service from the pipeline, particularly for short-term service. This has given shippers the choice of buying gas in upstream markets and transporting that gas to their downstream delivery points or purchasing gas directly in downstream markets.

²¹ Natural Gas Decontrol Act of 1989, H.R. Rep. No. 101-29, 101st Cong., 1st Sess., at 6 (1989).

On February 9, 2000, FERC issued Order No. 637 removing the price ceiling for short-term capacity release transactions for a trial period of two years. The order also revised pipeline scheduling procedures to facilitate capacity release transactions, and required pipelines to permit shippers to segment capacity wherever feasible. The changes were intended to provide shippers with additional flexibility to acquire transportation products that are better tailored to their needs, especially during peak demand periods.

Some have contended that elimination of the rate ceiling on released capacity played a role in the high prices experienced in the last several months. If large shippers can acquire sufficient capacity on constrained interstate pipelines, they may be able to charge very high rates for any other shipper that wishes to acquire some of that capacity. However, shippers probably had this ability even before Order 637; holders of capacity on key bottlenecks could extract the value of that capacity through sales of commodity gas, which are unregulated.

Northwest Pipeline

The Northwest Pipeline Corporation (a subsidiary of Williams) owns and operates a transmission system extending from points of interconnection with El Paso Natural Gas Company and Transwestern Pipeline Company near Blanco, New Mexico through the states of New Mexico, Colorado, Utah, Wyoming, Idaho, Oregon, and Washington, to the Canadian border near Sumas, Washington where it interconnects with the facilities of both Westcoast Energy, Inc. and Sumas International Pipeline Inc. Other major pipeline interconnections with Northwest's system include El Paso at Ignacio, Colorado; Colorado Interstate Gas Company, Questar Pipeline Company and Kern River Gas Transmission Company at various points in southwestern Wyoming; Paiute Pipeline Company at the Idaho/Nevada border and PG&E Gas Transmission, Northwest Corporation at Stanfield, Oregon and Spokane, Washington.

Northwest Pipeline is a one-third owner of the Jackson Prairie Storage Project in Lewis County, Washington and also owns and operates the Plymouth LNG facility in Benton County, Washington, both used by Northwest Pipeline to provide contract storage services. To assist in balancing its transportation services, Northwest Pipeline also has contracted for underground natural gas storage capacity from Questar in the Clay Basin Field in Daggett County, Utah.

Pipeline Operation and Natural Gas Flows

Northwest Pipeline is a bi-directional pipeline that relies on a combination of physical and displacement capacity to meet firm contract commitments. This allows for maximum utilization of pipeline capacity, achieving natural gas flows into and out of the pipeline system that are much higher than one-way physical capacity would allow. Because Northwest Pipeline has delivery and receipt points in a number of locations throughout the western states, customers in the southern portion of the system can contract for delivery of Canadian gas and those in the North can contract for gas from the Rocky Mountains or the San Juan Basin in New Mexico. Physically, contracted gas flows in opposite directions over the same pipe segment negate each other, so all the gas from Canada does not necessarily have to flow to the southern part of the system and vice versa. This phenomenon is called "displacement."

The operation of Northwest Pipeline involves balancing the natural gas input to the system with the output. This is a complicated undertaking because of the multiple delivery and receipt points and physical constraints on the system. The actual natural gas flow varies depending on a variety of circumstances including natural gas prices at various points on the system, physical pipeline constraints, and the flow demands (daily nominations) from shippers with contracts for receipt and delivery at various points.

Shippers contract for capacity by identifying a receipt and delivery point and the needed capacity. One way to get a sense of flow and capacity on Northwest Pipeline is to consider the contracted firm capacity inputs to the system at the various receipt points. The Northwest portion of the pipeline primarily receives natural gas from Sumas (from the Westcoast Pipeline), Stanfield (from GTN), and from receipt points in Wyoming, Colorado, Utah and New Mexico. Storage facilities at Jackson Prairie and Plymouth, Washington provide additional natural gas input. Table 3.1 identifies contracted firm capacity inputs at these receipt points.

Table 3.1. Contracted Capacity Receipts for the Northwest Portion of the Northwest Pipeline

Location	Receipt Point Firm Capacity (MDth/day)
Sumas	1,085
Starr Road	150
Stanfield	600
Palouse	20
Kemmerer	725
<i>Total w/o Storage</i>	<i>2,580</i>
Jackson Prairie	874
Plymouth LNG	300
<i>Total Storage</i>	<i>1,125</i>

Source: Northwest Pipeline

Each day, shippers with contracted capacity make nominations for the amount of capacity they will need. Generally, the daily nominations are less than the contracted capacity. The average ratio of nominated flows to total capacity, called the load factor, is approximately 83% of the Northwest Pipeline system. This has been fairly consistent for the last five years. Unused contracted capacity can be released on a daily basis. The load factor on different segments of the system can be higher (or lower) than 80% due to pricing dynamics, constraints on the system, and shipper nominations for specific points of receipt and delivery.

Physical constraints in pipeline capacity limit natural gas flow on parts of the Northwest Pipeline system and dictate how the pipeline is operated. Key constraint points include Kemmerer at the Idaho/Wyoming border, Roosevelt in the Columbia Gorge, and Chehalis in the I-5 corridor. Because physical capacity is limited at these points, displacement must be used to meet contract capacity for south flow or north flow design days. For example, domestic gas prices that are lower than Canadian prices have resulted in a north flow condition in recent months. The physical pipeline capacity at Kemmerer is 474,000 decatherms (474 MDth) per day, yet the contracted firm capacity is 725 MDth/day and given current natural gas prices shippers desire to use this capacity to ship less expensive domestic gas. The difference in contracted capacity and physical capacity is achieved through displacement, i.e., by moving 251 MDth/day south on a north flow design day.

However, significant disparities in price between Canadian and domestic gas make it difficult to achieve the design flow capacity through displacement. Similarly, on a south flow design day, natural gas needs to flow north from the southern end of the system through Fort Lewis to achieve the necessary displacement.

Physically, the majority of natural gas on Northwest Pipeline is from Canada (approximately 73%). Canadian gas enters the system at Sumas from the Westcoast Pipeline and at Starr Road, Palouse, and Stanfield from the GTN Pipeline. Contractually, the system is designed for a greater share of domestic supply (approximately a 53% Canadian/47% domestic split). In the summer of 1999, the contractual split was 72% Canadian and 28% domestic and in winter 1999 it was 65% Canadian and 35% domestic. These contractual amounts are achieved largely through displacement.

Table 3.2. Largest Shippers on Northwest Pipeline System

Shipper	Contracted Delivery (MDth/day)
Puget Sound Energy	456
Northwest Natural Gas Company	352
Pan-Alberta Gas (U.S.), Inc.	243
Cascade Natural Gas Corporation	208
Avista Corporation	200
IGI Resources	139
Duke Energy Trading and Marketing LLC	133
Sierra Pacific Power Company	69
Southwest Gas Corporation	68
CanWest Gas Supply Inc.	52
Pacific Gas and Electric Company	46
Weyerhaeuser	38
Petro-Canada	31
Boeing	29
TMSTAR Fuel Company	23

Source: Northwest Pipeline

Table 3.2 identifies the top 15 shippers on Northwest Pipeline based on contracted delivery. These shippers account for the majority of the contracted capacity on the system. The shippers include local distribution companies, energy marketers, and industrial customers. Most of these shippers are located in the Pacific Northwest. On any given day the mix of shippers on Northwest Pipeline varies from this list, since shippers with contracted delivery can sell unused capacity to other shippers.

Pipeline Capacity Issues

Capacity on Northwest Pipeline is fully subscribed, although some capacity is sold under short-term arrangements. Due to the design and physical capacity of the system, under certain conditions capacity on the system becomes constrained and displacement must be used to meet contract demand as noted above for Kemmerer. When there is a significant disparity between the price of natural gas at different points in the system, this can require the use of operational flow orders (OFOs) to achieve system balance. This situation is described in the following text excerpted from

information submitted by the Northwest Pipeline Corporation to the FERC for an interim displacement reduction project at Kemmerer.²²

From mid-November through year-end 2000, the spot-price differential between Canadian gas supply at Sumas, Washington and domestic gas supply at Opal, Wyoming was greater than \$2.00 per Dth, peaking at over \$34.00 per Dth during the second week of December. The scheduled net north flow (i.e. scheduled north flow minus scheduled south flow) through the Kemmerer Corridor is sensitive to gas price differentials between domestic supply sources south of Kemmerer and Canadian supply sources north of Kemmerer. When Canadian gas supply is more expensive than Wyoming gas supply, shippers understandably have attempted to maximize utilization of north flow capacity and minimize utilization of south flow capacity.

Since mid-November 2000, Northwest has had to regularly invoke OFO's under its tariff to make sufficient displacement capacity available to accommodate firm contractual obligations for north flow service through the Kemmerer Corridor. Such general OFO's likely will continue to be required during periods of pricing disparity in favor of domestic over Canadian gas sources. The first remedial measure in Northwest's general OFO provisions is a "primary receipt point realignment" and the second is a "must-flow" requirement. Prior to invoking general OFO mechanisms, Northwest must ameliorate the operational condition, to the extent possible, with scheduling/entitlement procedures and available contract-specific OFO's.

Under the primary receipt point realignment OFO, shippers with primary receipt rights on both sides of the Kemmerer Corridor have been required to realign nominations from domestic receipt points to otherwise unscheduled primary Canadian receipt points. (A shipper required to realign nominations may simply elect to reduce north flow nominations without nominating equivalent volumes from its available primary Canadian receipt points.) Most of the firm north flow capacity through the Kemmerer Corridor is dedicated to major local distribution company shippers in the Pacific Northwest under transportation agreements that also include primary firm transportation capacity rights from Canadian receipt points. Recently, such shippers (directly or through capacity releases) typically have been fully utilizing their contract demands, so minimal primary receipt point realignment potential exists.

The must-flow OFO has required shippers holding primary firm south flow rights through the Kemmerer Corridor to flow a pro rata share of contract demand through that corridor to provide displacement. During December, must-flow OFO's required shippers to flow an average of approximately 16% of south flow contract demand; i.e. an aggregate average of approximately 36 MDth per day.

With the OFO's, Northwest's scheduled net north flow through the Kemmerer Corridor averaged approximately 495 MDth per day during December. Northwest's operationally available physical capacity exceeded its 474 MDth per day of theoretical design capacity primarily due to colder ambient temperatures and a higher actual thermal conversion factor.

²² APPLICATION FOR A BLANKET CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY: INTERIM KEMMERER DISPLACEMENT REDUCTION PROJECT, Filed by Northwest Pipeline Corporation, January 5, 2000

Although the recent OFO's have worked as designed to provide required displacement capacity, the magnitude and duration of the OFO's has caused considerable consternation among the affected shippers. Under the "realignment" OFO, some north flow shippers have been required to realign to use more expensive Canadian gas in lieu of domestic gas. Under the "must flow" OFO, south flow shippers have been required to market expensive Canadian gas to comparatively uneconomic markets at primary delivery points south of Kemmerer.

This description illustrates the challenges to achieving design flows on the Northwest Pipeline system using displacement when there are significant gas price differentials at different points on the system. The necessity to implement OFOs stemmed from extreme basis differentials on either side of Kemmerer. Whereas historically, Sumas gas has been cheaper in the summer and domestic gas cheaper in the winter, Sumas is now trading at a premium year round and the magnitude of this premium was extremely large at times during late 2000 (up to \$30/MMBtu in daily markets).

In January, 2001, Northwest requested FERC approval to relocate three existing portable compressors into the Kemmerer to Stanfield corridor in order to move additional gas. In an unusually quick process, FERC approval was granted in early February 7, and the compressors quickly placed into operation. Despite basis differentials approaching those that led to the November situation, no OFOs have been necessary in the first three months of 2001.

Existing shippers on Northwest Pipeline are largely utilizing their firm capacity on the pipeline. Thus there is little available pipeline capacity. Contracts for approximately 20% of the capacity on the pipeline expire in the next three years and about half the capacity contracts expire by 2008. However, most large shippers have unilateral extension rights on a year-to-year basis. Thus the expiration of these contracts is unlikely to free up capacity on the pipeline to other shippers or force existing shippers off the pipeline.

As pipeline capacity is more fully utilized, players that rely on interruptible capacity will be squeezed out. As capacity is rationalized, i.e., turned back to the pipeline for resale as firm during an open season, it becomes unavailable. As capacity becomes more constrained, this influences price. If there is a limited amount of capacity and customers chasing cheap gas, the system may not be able to deliver the cheap gas and many customers may have to pay a premium to get gas from another point.

PG&E Gas Transmission Northwest (GTN) Pipeline

The GTN Pipeline is owned and operated by PG&E National Energy Group, a subsidiary of PG&E Corporation, which also owns Pacific Gas and Electric Company of San Francisco. The GTN pipeline interconnects with TransCanada at Kingsgate, British Columbia; Northwest Pipeline at Spokane and Palouse, Washington, and Stanfield, Oregon; and Pacific Gas and Electric Company and Tuscara Gas Transmission Company at Malin, Oregon. GTN also connects with Avista Utilities and Cascade Natural Gas.

Pipeline Operation and Natural Gas Flows

GTN is a dual pipeline system consisting of approximately 630 miles of 36 inch diameter gas transmission line (612 miles of single 36 inch-diameter pipe and 27 miles of 36-inch-diameter pipeline looping) and approximately 590 miles of 42-inch-diameter pipe. The system also includes smaller diameter laterals to Coyote Springs and Medford. GTN can transport about 2.7 billion

cubic feet of gas per day, or 2,700 MDth/day. More than 1,800 MDth/day can be delivered to California and Nevada and up to 1,000 MDth/day to the Pacific Northwest. In 2000, typical deliveries to the Pacific Northwest from the GTN system averaged 522 MDth/day in the winter and 300 MDth/day in the summer.

Natural gas flow on the GTN system is essentially one-way from Canada to California. Gas can be delivered at various points along the system including three interconnection points with Northwest Pipeline and direct connects to local distribution companies such as Avista and Cascade Natural Gas. GTN also delivers to generators at Coyote Springs and Hermiston, Oregon. Natural gas is received primarily from TransCanada Pipeline at Kingsgate, BC, but GTN can receive a small amount of gas from the Northwest Pipeline at Stanfield. Even though there is not physical capacity to receive gas at other locations, it is possible to have nominations for receipt at other points by using displacement at other points on the system.

Generally, the GTN pipeline has been operating at or near capacity for a number of months. On the northern part of the system the load factor has been 90 to 100% depending to some degree on domestic and Canadian gas prices. The southern end of the system has been operating at virtually 100% capacity since last summer.

GTN has 2,732 MDth of firm transportation capacity under contract (see Table 3.3), or 100% of its nominal transportation capacity. Nearly all of these contracts have expiration dates in 2005 or later. GTN's customer list is substantially different from that of Northwest Pipeline. The majority of gas transported by large customers like Pacific Gas & Electric Company is passing through the GTN system en route to California. The exceptions are Avista Corporation, Northwest Natural Gas Company, Puget Sound Energy, Pan-Alberta Gas (US), Inc., PanCanadian Energy Services, Duke Energy, and Chevron USA Inc., all of which deliver to points in Washington and Oregon.

Table 3.3. Largest Shippers on the PG&E Gas Transmission Northwest Pipeline

Company	Maximum Daily Quantity (MDth/d)	Primary Delivery Points
Pacific Gas and Electric Company	610	Malin
Pan-Alberta Gas (U.S.), Inc.	290	Stanfield and Malin
Avista Corporation	167	Various
Duke	166	Stanfield, Hermiston, and Malin
PanCanadian Energy Services, Inc.	105	Stanfield and Malin
Puget Sound Energy	102	Spokane and Stanfield
Northwest Natural Gas Company	98	Spokane and Stanfield
Chevron USA, Inc.	91	Hermiston and Malin
Southern Company	91	Malin
Sierra Pacific Resources	84	Malin
Others	928	Various
<i>Total Existing Contracts</i>	<i>2,732</i>	

Source: PG&E National Energy Group

Pipeline Capacity Issues

Demand for pipeline capacity on the GTN system is influenced strongly by demand for new and planned natural gas generation capacity in the Northwest and California. Four plants are currently under construction on the GTN system in the Northwest. One new plant under construction in California is owned by PG&E and other proposed plants in California could potentially create demand on the GTN system. General load growth has created some demand for new capacity from local distribution companies. On a simultaneous peak day there is not enough capacity to serve these new loads. Currently, the system is operating near full capacity.

Natural Gas Storage

In addition to flowing gas from pipelines, Washington's gas utilities rely on underground storage fields to meet peak demands. Jackson Prairie, near Chehalis, Washington is owned by Avista Corporation, Puget Sound Energy and Northwest Pipeline in equal shares. The Mist, Oregon storage facility is owned by Northwest Natural. In addition, Questar has a storage facility at Clay Basin in Northeast Utah in which capacity is held by Puget Sound Energy, Northwest Pipeline and other regional shippers.

These facilities are primarily used for seasonal storage to increase peak day deliverability. Gas is injected during off-peak periods and retrieved during the peak winter heating season. Refill begins in spring and continues through October, when 90-100% of capacity is usually achieved. As much as half of the gas used by consumers on a cold winter day comes from storage fields. After a November, 1999 expansion, Jackson Prairie has a daily withdrawal capacity of 874 MDth. Working gas capacity was expanded from 15,100 MDth to 18,300 MDth. An additional expansion is currently under study.

Puget and Avista use their portions of Jackson Prairie to provide peak day deliverability for their core customers. Unneeded portions may be leased to third parties on an interim basis. Northwest Pipeline does not market natural gas commodity -- its portion of the facility is either used to provide balancing gas or leased to shippers (Puget has arrangements for 15-20% of Northwest's share of Jackson Prairie). Gas from Jackson Prairie flows into the Northwest Pipeline system, where it is delivered to the specified delivery point. Each of the three owners can nominate flows independently of each other.

The location of major storage facilities close to end-use customers allows storage to substitute for pipeline capacity in meeting peak demand days. Because gas can be shipped to storage facilities west of the Cascades during the summer when interstate pipelines operate at less than 100% capacity, these pipelines need not be sized to meet downstream peak demands. This means that the value of natural gas storage to the Northwest is not derived solely from winter/summer price differentials, but also from savings from avoided pipeline upgrades. The fact that these facilities are needed to meet peak winter demands also explains why storage facilities in the Northwest were refilled to capacity last summer and fall despite higher gas prices, while across the country less gas was placed into storage than in past years.

As the demand for natural gas for electricity generation increases, there may be less gas available during off-peak periods for injection into storage facilities, and the gas that is available may be more costly. Peak electricity demand in the Southwest occurs in summer. If natural gas prices become more sensitive to the price of electricity, this may mean that natural gas will no longer be significantly cheaper during summer months. The risk management strategies historically used by

local gas distribution utilities may need to be revised in order to minimize the cost of gas service to traditional core-market customers as gas-fired electric generation is added to regional natural gas demand.

Table 3.4. Natural Gas Storage Facilities Available to the Pacific Northwest

Name	Withdrawal Capacity (MMcf/day)	Pipeline	Location
Jackson Prairie	850	NWP	Centralia, WA
Clay Basin	450	NWP	Northeast Utah
Plymouth LNG	300	NWP	Columbia Gorge area, WA
Mist	190	NWP	Northwest of Portland, OR
Gasco LNG	120	NWP	Near Portland, OR
Newport LNG	60	NWP	Newport, OR
Columbia Hills	(Proposed)	NWP and GTN	

Pipeline Expansion

Increases in gas demand require increases in pipeline system capacities. Upgrades to interstate pipelines can require substantial investments, as well as federal and local permits. The ability of LDC systems to complete needed upgrades is beyond the scope of this report. LDC upgrades can also be costly and may also require state and local permits.

While the existing pipelines are fully subscribed, each has the ability to expand its capacity. The first step is to ascertain what level of capacity customers desire. This is done through an “open season” in which any shipper of natural gas can request additional capacity. Existing shippers may also turn back unneeded contracted capacity, reducing the need to add physical capacity. If the pipeline company receives sufficient interest during the open season to justify expanding capacity, it applies to FERC for a Certificate of Public Convenience and Necessity authorizing the project to go forward. New pipeline capacity is not developed unless firm commitments are in place with shippers for the new capacity.

There are two methods available for increasing pipeline capacity: increasing operating pressure or increasing cross-section. Increasing operating pressure requires upgrading or adding compressor stations, requiring some capital investment. Increasing cross-section is theoretically equivalent to increasing the diameter of the pipe, but in practice is achieved by laying additional pipe parallel to the existing pipe. The second pipe is referred to as “looping” pipe. The parallel pipes are treated as a single system for commercial purposes.

The costs of new capacity can be allocated on either a “rolled in” or an “incremental” basis. If the cost of expansion is relatively minor, adding both the new costs and the new throughput to the existing rate base may result in rates that are lower than before the expansion. In this case, costs of the expansion are rolled into existing rates. If substantial new investment is required such that rolling in the expansion costs would result in rate increases for existing shippers, the costs may be assigned on an incremental basis. That is, the new shippers pay the costs of the new capacity, while existing shippers continue to pay the same rate.

Following the open season, when all the shippers’ needs are known, the cost of expansion is finally estimated and the application is made to FERC. The application process can take up to 18 months. However, FERC may be able to expedite the process on an emergency basis and has proposed

expedited approval in 2001 for expansions that can come online quickly. After FERC's decision on a rate design, customers can execute contracts for the additional capacity and, once all the necessary approvals are received, the project enters the construction phase. The timeline from the beginning of open season, through all the permitting to the start of construction is two to three years. Construction time depends on the nature of the project, but ranges from a few months (for adding compression) to two years (laying extensive new pipe).

The importance of FERC's role in this process is worth some emphasis. FERC's pricing policy can have a significant effect on which expansion projects go forward. FERC considers the market demand, impact on existing customers and ultimately decides if a project is incremental or not before issuing the Certificate of Public Convenience and Necessity. If a project is deemed incremental, shippers may have the option of dropping out and the project may be cancelled.

Northwest Pipeline Expansion Plans

Northwest Pipeline Company has identified several opportunities for expansion. Table 3.5 outlines recent plans. Further discussion for each expansion project follows.

Columbia Gorge Expansion

Northwest recently completed a 50 MDth/day expansion project in the Columbia Gorge. A larger scale expansion project is not being planned now. Additional expansion increments can be phased in to meet new demands in the I-5 corridor.

Sumas to Chehalis Expansion

Northwest Pipeline conducted an open season for this expansion in December, 2000. The open season will result in firm capacity for 277 MDth/day, including new capacity of 224 MDth/day (the remainder will be existing capacity that is either available or has been turned back by firm shippers). The company is in the process of signing agreements with the six customers that indicated interest during the open season. The shippers will be identified when the company submits its application to FERC in July 2001. Northwest hopes to have preliminary FERC approval in January 2002, certificate for construction in July 2002, start construction that summer and begin operation in June 2003. Part of the regulatory process will determine how much of the expansion can be rolled into existing system costs.

Table 3.5. Northwest Pipeline/Williams Expansion Plans

	Capacity (MDth/day)	Cost (million \$)	Compression (horse power)	New Pipe (miles)	Service Commencement
Columbia Gorge Expansion	50	35.5	14,600	6	Completed Nov. 1, 1999
Sumas to Chehalis Expansion ¹	224	N/A	N/A	N/A	June 2003
Opal to Stanfield Displacement Replacement	175	125	24,000	90	Nov. 2003
Georgia Strait Pipeline	94	159	9,400	85	Nov. 2003
Grants Pass Lateral Expansion	136	64.9	14,300	45.4	Project postponed

¹ Incremental capacity only. The open season will also include 53,000 Dth/day of existing capacity that is either available or has been turned back by firm shippers.

Source: Northwest Pipeline

Opal to Stanfield Expansion or Displacement Project

Northwest is currently planning to seek FERC approval to construct and operate new facilities that would reduce reliance on displacement by 175 MDth/day through the project corridor (in the Kemmerer, Wyoming region). This project will not result in new capacity being made available to the market, but will allow for more effective use of existing firm capacity by reducing reliance on displacement between Green River, Wyoming and Stanfield, Oregon. Providing new northflow capacity would require upgrades in the Columbia Gorge area as well as at Kemmerer, and is not planned at this time.

Georgia Strait Crossing (GSX) Project

This proposed new pipeline connecting Sumas to Vancouver Island is a joint venture of BC Hydro and Williams, the parent of Northwest Pipeline. The GSX Pipeline would be constructed and operated by a Williams affiliate (yet to be determined), and would cross overland from Sumas to Ferndale, and then underwater to a point north of Victoria. It is designed to serve growing gas demand, primarily for electric generation, on Vancouver Island. An open season was conducted in 2000 which resulted in Powerex Corp., BC Hydro's power marketing subsidiary, contracting for the entire initial design capacity of 94 MDth/day. It is anticipated that compression will be added within the first few years of project operation to meet new industrial, power generation and commercial demand on both sides of the Strait.

The GSX system will comprise one 9,700 horsepower compressors and 85 miles of pipe including:

- 33 miles of 20-inch diameter onshore pipeline in Washington
- 15 miles of 16-inch diameter offshore pipeline in U.S. waters
- 27 miles of 16-inch diameter offshore pipeline in Canadian waters
- 10 miles of 16-inch diameter onshore pipeline on Vancouver Island

Applications to FERC and the Canadian National Energy Board will be submitted during the second quarter of 2001. Regulatory approvals are anticipated in 2002 to allow the GSX sponsors to meet a November, 2003 in-service date. This project will not add gas supply capability to Washington unless it is accompanied by additional expansion of either the West Coast or Northwest Pipeline systems between Sumas and gas-producing areas.

Grants Pass Lateral Expansion

This project would have addressed anticipated market growth and new electric generation loads from Portland south to Grants Pass. The lateral-only expansion was designed to loop 45 miles of pipe and upgrade existing compression. This project was postponed due to lack of interest on the part of prospective shippers. Northwest Pipeline is continuing to discuss requests for firm capacity with interested parties.

GTN's Pipeline Expansion Plans

GTN has identified a three-phase expansion plan (Table 3.6). This includes compression upgrades on the existing system, and construction of a pipeline across the Cascades to Western Washington. The first phases of this could be completed in time to serve Eastern Washington generating facilities in the next five years; the cross-Cascades pipeline is a longer-range proposal. This would require an expansion on the TransCanada Pipeline in order to bring additional gas to its Kingsgate interconnection with GTN.

Table 3.6. GTN Pipeline Expansion Plans

	Capacity MDth/day	Cost (million \$)	Compression (horsepower)	Pipeline (miles)	Timeline
2002 Expansion – Kingsgate to Malin	200	115	75,000	21 (Looping)	June, 2002
2003 Expansion – Kingsgate to Malin	200-500 (depends on interest)	TBD	TBD	TBD	Late 2003
Phase Two – Vantage Pipeline	300-500 (speculative)	More than Phase One	Much less than Phase One	260-270 (new)	2004
Phase Three – Alaskan and MacKenzie Delta Pipeline	6,000 – 7,000	unknown	unknown	Unknown	2008

Source: PG&E National Energy Group

GTN completed an open season in February, 2001, for 200 MDth/day. The winning bidders were Newport Northwest, L.L.C., developer of a 1300 MW power plant in Wallula, Washington, and Calpine Corporation, which has several generating projects in construction or development in the Pacific Northwest and California, including a plant under construction in Hermiston, Oregon. The proposed Phase One will lay about 21 miles of new pipes in one continuous section, but most of the new capacity will be through compression. PG&E will apply to FERC in April and will request expedited approval of the expansion, so that partial service can begin as early as next winter, with full service available by summer 2002. TransCanada has indicated that, upon receipt of signed contracts with its expansion shippers, it plans to seek regulatory approval to expand its Alberta and British Columbia systems upstream of the GTN facilities to ensure a matching of downstream capacity at Kingsgate.

During the recent open season, shippers expressed interest in a total of 2,100 MDth/day - ten times what was being offered. The majority of the requests were from California electricity generators, although some California gas utilities were also represented. Based on this response, GTN announced a second open season on May 7, 2001, for up to 500 MDth/day, with service planned to commence in November, 2003.

The overwhelming response to the 2000 open season will also push Phases Two and Three into high gear. Phase Two is speculated to bring on an additional 300-500 MDth/day, based on recent interest in new capacity. The cost of Phase Two will be somewhat more than Phase One because it will require opening a new corridor and laying three segments of new pipe in different locations. Phase Two will also be more expensive than current system average cost and will likely be priced incrementally.

If current prices continue, planning will go forward for Phase Three, with a targeted in-service date of 2008. Phase Three would connect GTN to the Alaskan Natural Gas Transportation System (ANGTS), which was started in the 1980s but never completed. This pipeline was designed to connect to GTN's system through the Canadian system. Large quantities of natural gas are currently being reinjected into crude oil wells in the MacKenzie Delta and Alaskan North Slope areas. This gas would be connected to the ANGTS transmission system and brought to market through GTN.

Orca Pipeline

Westcoast Energy, Inc. proposed construction of a new pipeline from Sumas to Everett, and then across Puget Sound to Port Townsend. If built, this would provide competition to Northwest Pipeline in the central Puget Sound area. However, unless the Westcoast Pipeline system north of the Canadian border is expanded, Orca would not increase the total amount of gas supply available in the state of Washington. This project has been put on hold due to lack of interest and is unlikely to go forward as currently envisioned.

Canadian Expansion Plans

Expansion of the GTN and Northwest Pipelines will not result in additional ability to deliver gas to consuming areas in Washington unless pipeline capacity from producing fields in northern British Columbia and Alberta to interconnection points at Sumas and Kingsgate is also expanded. There are at least two options for expanding this capacity that are currently under consideration.

Westcoast Pipeline

Westcoast has identified approximately 300 MDth/day of additions on its main line from the British Columbia gas fields to Sumas. These would involve a modestly higher delivery rate than the current pipeline transportation tariff.²³ In February, 2001, Westcoast announced that shippers had fully renewed all firm service on its Southern mainline transportation facilities. This means that all available annual contractible firm service on Westcoast's mainline north of Compressor Station 2 (with the exception of certain facilities in the Fort St. John area) and on Westcoast's Southern mainline from Compressor Station 2 to Sumas are fully contracted on a firm basis. Westcoast is now assessing options for expanding capacity on its Southern mainline to meet growing demand in traditional markets and new gas-fired generation in the Pacific Northwest.

Farther up the Westcoast system in the Narraway and Grizzly gas production regions (near the Pine River Valley), a 16 inch pipeline is being proposed that would transport raw gas to the existing Grizzly Valley Pipeline system. Construction is scheduled to begin in mid-July 2001, pending regulatory approval, and in service by December, 2001. This connection eventually feeds Northwest Pipeline and the Alliance Pipeline.

Southern Crossing/IPC Pipeline

BC Gas is planning an extension of its existing Southern Crossing Pipeline to Sumas. The Southern Crossing Pipeline, completed in November, 2000, connects the TransCanada system to the BC Gas distribution system in the Southern Interior of British Columbia. The current capacity is 250 MDth/day, which is used to displace capacity on Westcoast which formerly served the Southern Interior areas.

BC Gas announced an open season on the extension, called the "Inland Pacific Connector" (IPC) Project, on May 7, 2001. The project would involve 150 miles of 24" pipe and additional compression, and would bring up to 350 MDth/day of new capacity to Sumas. The project is expected to cost around \$300 million (U.S.), resulting in a transportation toll of approximately 34 cents per MMBtu. BC Gas is currently in discussion with TransCanada about a matching expansion of that system upstream of the interconnection point at Yahk, British Columbia. BC Gas is targeting an in-service date of November, 2003.

²³ Presentation of Douglas Haughey, President, Pipeline and Field Services Division, Westcoast Energy, Inc. Ziff Energy Group gas conference, June, 2000.

Implications

The Northwest and GTN pipelines are currently operating at or near their capacity. There is no firm capacity available and as the load factor on the pipelines grow, the availability of non-firm capacity is likely to be limited. It should not be surprising that existing pipelines are not sized to meet large new demands for natural gas. Federal policy prevents the construction of unneeded pipeline capacity by requiring that a market exist for that capacity. Under current rules, FERC does not grant approval for the construction of new pipeline capacity unless prospective shippers are willing to commit to long-term contracts for the new capacity.

Demand for gas in 2000 increased at a much faster rate than expected by pipeline companies and major shippers, due largely to greatly increased use natural gas for electric generation necessitated by higher electric demand and lower hydroelectric production. The interstate pipeline system showed severe strain, resulting in price volatility and large price differentials at various points on pipelines serving West Coast markets. This demonstrates that even the existing level of gas consumption for electric generation during low hydro years is not sustainable with current infrastructure; meeting new demand will require major investments in pipeline capacity.

However, pipeline expansion activities are underway. Recent open seasons on both pipelines serving the Northwest have generated sufficient interest for some planned expansion projects to move forward. These expansions will likely ease constraints on the existing pipelines, although the proposed increases in capacity are relatively modest. The significant interest in the GTN open season suggests there may be sufficient support for larger pipeline system expansions to meet new load from natural gas-fired electricity generation. From the standpoint of the pipelines, the question is how much of this new load will actually materialize and whether potential shippers are willing to commit to contracting for new pipeline capacities. The lead times for developing new pipeline capacity are comparable to the construction time for new power plants, providing the opportunity to develop the infrastructure to support new plants coming on-line. Expansions on upstream pipelines such as TransCanada and Westcoast would be required to bring additional Canadian gas supplies to the region.

Section 4. Natural Gas Production

The majority of Washington's natural gas supply comes from Canada. Northwest Pipeline connects Western Washington and Oregon with British Columbia supplies at the Sumas, Washington border crossing, while the GTN pipeline transports Alberta gas to eastern Washington, Oregon and California. Northwest Pipeline also connects the state to gas sources in the Rocky Mountain and San Juan regions, and natural gas can be purchased in the Rockies or San Juan on behalf of Northwest customers even if the actual molecules of natural gas come from Canada. Both producing regions are therefore important to Washington gas consumers. This chapter provides a brief survey of the issues relating to future natural gas production in these regions.

During most of the 1990s, the Pacific Northwest benefited from the lack of alternative markets for inexpensive Canadian gas supplies. However, the supply picture has changed dramatically in the last few years. Several new long-distance pipelines have entered service, and the Canadian gas producers now have much greater access to markets beyond California and the Pacific Northwest. The biggest of these, the Alliance Pipeline from producing fields in Alberta and British Columbia to Chicago, was placed into service at the end of November, 2000 with a capacity of 1,300 MDth/day. The completion of major pipeline networks from Canadian and Rocky Mountain producing fields to East Coast markets means that any increases in gas supplies from major domestic producing regions such as the Gulf of Mexico will result in greater gas availability and lower prices for Northwest customers. Conversely, the Northwest will no longer be insulated from demand events such as cold snaps in the Midwest and Northeast that can drive natural gas prices higher. Natural gas is being traded in an increasingly North American market. A sophisticated analysis of the entire North American natural gas market is beyond the scope of this report.

Traditional Gas Supplies

North American Gas Reserves

The U.S. Energy Information Administration currently estimates that the lower 48 states and Canada have approximately 230 trillion cubic feet (Tcf) of proven natural gas reserves. At a combined rate of annual consumption of 24.7 Tcf per year, North American natural gas reserves would be depleted in 9.4 years if no natural gas reserves were added. These numbers are presented below in Table 4.1.

Of course, this calculation is overly simplistic. Each year, existing gas reserves are depleted, and additional new reserves are discovered. Gas exploration is going on continuously and new natural gas fields are discovered and brought into production on a regular basis.

Demand is also increasing. Each year, new homes are constructed that burn natural gas for heating, cooking and heating water. New factories and businesses are contributing to higher gas demand. And most importantly, the current trend towards burning natural gas to generate electricity will greatly increase gas demand over historic levels. The question for the future is whether new fields will be sufficient both to replace existing fields where production is declining and to keep pace with growing demand.

Moreover, estimates of natural gas "reserves" are necessarily uncertain. It is useful to understand the different ways in which reserves can be characterized. For the purposes of this report, we use three terms. "Proven Reserves" is an economic term meaning gas that is located in gas fields that have been developed and are capable of producing gas now, and for which analysis has been

completed of the extent of available gas. The level of proven reserves of natural gas is a dynamic statistic that depends on economics, e.g., whether it is economic to produce the gas at current prices, in addition to physics. “Undiscovered Resources” means amounts of gas that are estimated to be developable at reasonable cost; only a portion of this is assumed to be capable of being produced and brought to market at profitable prices. “Endowment” is a geological estimate of the total amount of gas available in an area prior to the development of any gas wells. It is the sum of gas already produced, gas available from remaining marketable reserves, gas which has been located but is not producible and marketable, and gas which is in undiscovered reserves. None of the amounts of gas described by these terms can be taken as fixed; even estimates of total gas endowment are frequently updated based on results of exploration.

Table 4.1. North American Natural Gas Reserves²⁴

U.S. Dry Natural Gas Proven Reserves as of 12/31/99	167.4 Tcf
<i>Texas</i>	<i>40.2 Tcf</i>
<i>Gulf of Mexico Federal Offshore</i>	<i>25.1 Tcf</i>
<i>New Mexico</i>	<i>15.1 Tcf</i>
<i>Wyoming</i>	<i>13.4 Tcf</i>
<i>Oklahoma</i>	<i>11.7 Tcf</i>
<i>Alaska</i>	<i>9.7 Tcf</i>
<i>Louisiana</i>	<i>9.4 Tcf</i>
Canadian Proven Natural Gas Reserves as of 1/1/00	63.9 Tcf
Total U.S. and Canadian Proven Natural Gas Reserves	231.3 Tcf
1999 U.S. Natural Gas Consumption	21.7 Tcf
1998 Canadian Natural Gas Consumption	3.0 Tcf
Approximate U.S. and Canadian Annual Gas Consumption	24.7 Tcf
Years of reserves with no growth in demand or reserves:	9.4 years

Sources: Energy Information Administration: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1999 Annual Report; Natural Gas Annual 1999; Country Analysis Briefs

Western Canadian Sedimentary Basin

Canadian natural gas comes from fields in the far north of British Columbia and Alberta, a geologic area known as the Western Canadian Sedimentary Basin (WCSB). It is processed to remove impurities, and then piped south. The gas can flow south through British Columbia on a pipeline owned by Westcoast Energy, Inc. through Alberta on the TransCanada pipeline to Kingsgate, BC, or east to markets on the East Coast of the U.S. and Canada through the TransCanada or Alliance pipelines.

The geographic area of natural gas exploration in British Columbia and Alberta is enormous – larger than the area of Washington and Oregon combined. Development conditions are harsh: most of the area is swampy in summer, and bitter cold in winter. Much of the development takes place during the winter months when the ground is frozen and heavy equipment can be moved. Equipment failures are relatively frequent due to the harsh weather.

²⁴ Currently, natural gas imports from and exports to Mexico are about equal. For this reason, we disregard Mexico as a supplier of gas in this simplistic analysis.

Current estimates of proven reserves in Canada are relatively modest. Total proven reserves in Alberta are 38 Tcf, and in British Columbia are 7 Tcf.²⁵ At current production rates in Canada, this is about a 10-year supply. The discovery and development of new reserves is a continuing process, and it is reasonable to anticipate significant additional gas will be found. The short life of proven reserves should not therefore be a cause for alarm. The National Energy Board estimates that an additional 185 Tcf of gas remains in undiscovered reserves.²⁶ Petro-Canada estimates that only about 30% of the total available Canadian gas endowment has been produced to date.²⁷ The price at which such new gas may be available is less certain.

The past five years have been a period of soaring growth in the Canadian gas industry. The number of wells drilled has more than doubled since 1995. The growth in gas well drilling has been necessary to keep up with growing gas demand, and to replace wells that are “tapped out.” Figure 4.1 shows the number of natural gas wells drilled each year in Western Canada since 1995.

Just counting the number of wells drilled, however, does not indicate the amount of gas being found. The size of the gas deposits now being developed is much smaller than in the past – as Figure 4.2 indicates, the average “pool size” for the “Undiscovered marketable” gas reserves in Western Canada are only one-tenth the size of those already producing. As Petro Canada reported at a recent conference: “With the average pool size decreasing, greater resources for capital, drilling, and infrastructure will be required.”²⁸ This translates into higher costs for natural gas production.

When a gas well is initially developed, the gas is under pressure and comes to the surface very rapidly. As the pressure subsides, the production from any given well can drop off relatively quickly. According to the National Energy Board, Canadian well productivity declines 18-35% per year, depending on the type of well and geographic location.²⁹ As a result, much of the new drilling is needed just to maintain existing production levels. In order to increase production, a very rapid drilling program is needed. For example, while the number of wells drilled in Canada has been increasing at about 15% per year for the past five years, the actual gas production has increased at only about 2-3% per year in this same period.³⁰

Domestic Gas Supply

While natural gas is found at many different locations in the United States, Washington is dependent on other states and Canada for all of our gas. The Washington Department of Natural Resources has recently leased some state lands for oil and gas exploration, but currently the state has no known commercially viable natural gas deposits.

²⁵ National Energy Board, Canadian Energy Supply and Demand to 2025, Table 5.1

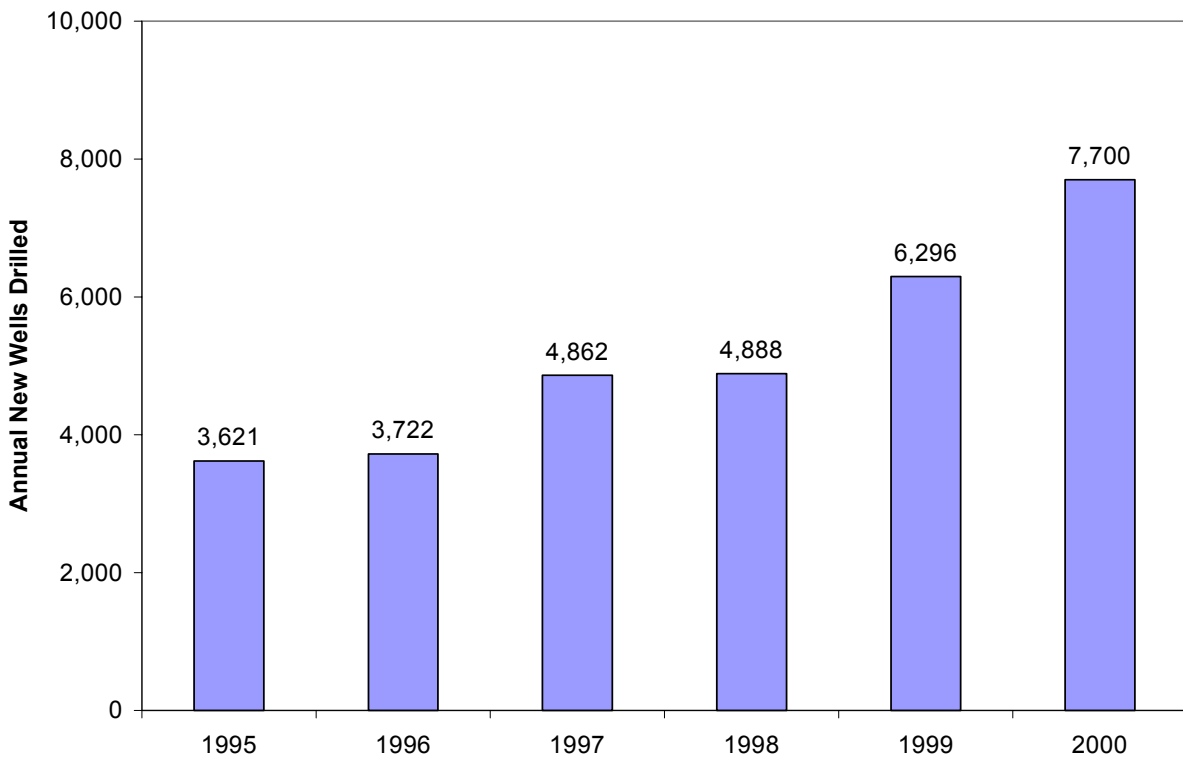
²⁶ Ibid

²⁷ Presentation of Heather Scott, Petro-Canada Oil and Gas, Ziff Energy Group Natural Gas Conference, June, 2000

²⁸ Heather Scott, Petro Canada, at Ziff Energy Natural Gas Conference, Seattle, June, 2000.

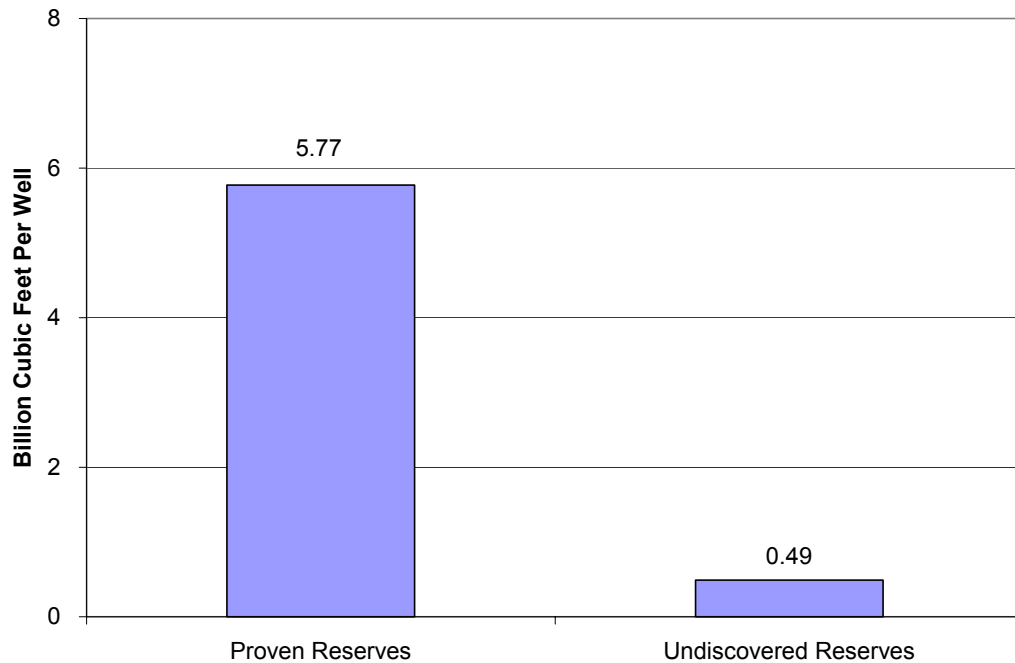
²⁹ NEB, Short-term Natural Gas Deliverability from the Western Canada Sedimentary Basin 1998 - 2001, June, 1999, P. 15

³⁰ Petro Canada, Op. Cit.



Source: Petro-Canada

Figure 4.1. Gas Wells Drilled in Canada, 1995-2000



Source: Petro-Canada

Figure 4.2. Average Gas Pool Size in the Western Canadian Sedimentary Basin

Proven reserves in the United States as of the end of 1999 totaled 167 trillion cubic feet.³¹ About half of the nation's proven gas reserves are in Texas, Louisiana, and in offshore wells in the Gulf of Mexico. About a quarter are in the Rocky Mountain states of New Mexico, Wyoming, and Colorado. The rest are spread out in small pockets from Alaska to Florida, and California to New York.

After falling off during the 1990s, natural gas drilling in the U.S. has picked up dramatically over the past 18 months, as demonstrated in Figure 4.3. The low level of drilling activity in previous years is an indicator of the cyclical nature of investment in commodity industries. When prices are low, investment in new supplies drops off. The lack of new resources coming on line eventually results in supply pressures, which leads to higher prices and renewed interest in finding new supplies. However, the lead time required to bring new resources to market frequently means that periods of high prices can linger for several years.

Moreover, the lower productivity per well that has been experienced in Canada as smaller and smaller deposits are exploited may become evident in the United States as well. If this occurs, it would mean that many more wells must be drilled just to maintain current levels of production, adding to the cost of new supplies.

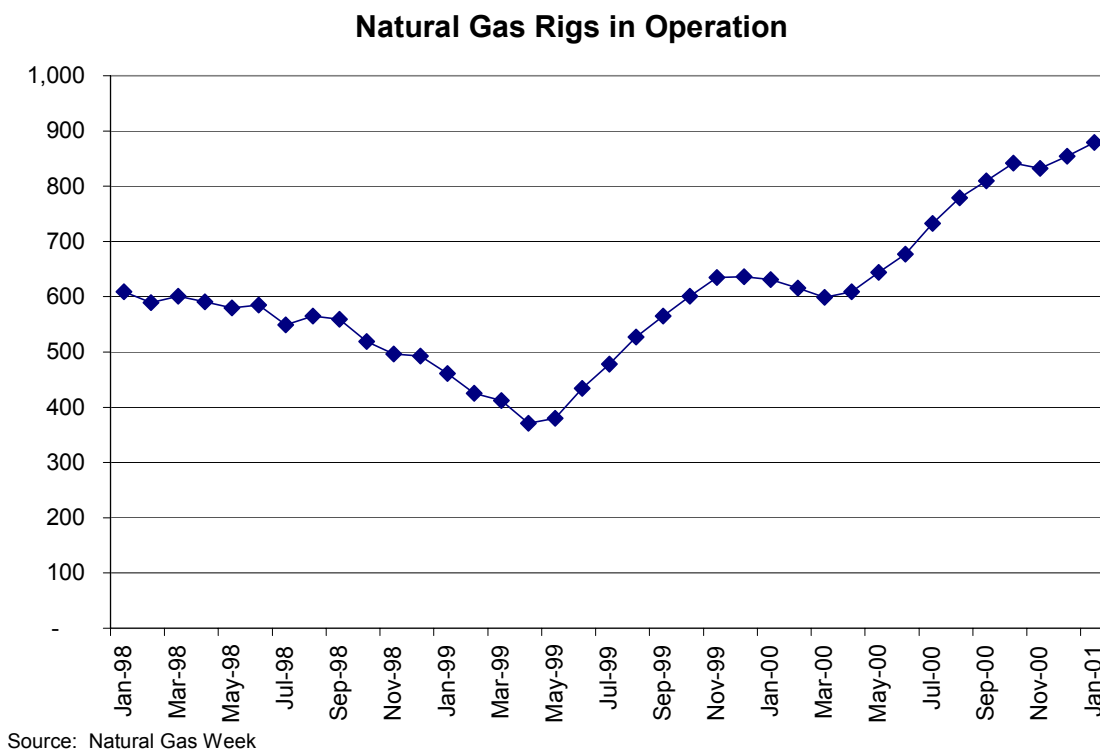


Figure 4.3. U.S. Natural Gas Drilling Activity

The Rocky Mountain states are the most important source of domestic natural gas supply to the Pacific Northwest. Gas production in the Rockies grew from 3.64 Tcf in 1995 to 3.96 Tcf in 1999. This growth may continue in the near term, as proven reserves increased 3.5% in Wyoming and 13% in Colorado between 1998 and 1999.

³¹ EIA U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1998 Annual Report, P. 35-36. This figure does not include approximately 35 Tcf of natural gas reserves on Alaska's North Slope, that are not currently placed into the "proven" category due to lack of pipeline capacity to downstream markets.

The largest natural gas producing area in the lower 48 United States is the Gulf Coast region of Texas and Louisiana. Gulf Coast gas affects Northwest prices by reducing demands in the eastern part of the United States for Rocky Mountain gas or by competing with Canadian producers for markets in the Midwest and East, leaving Canadian supplies to serve the West Coast. Production in this region did not grow in the 1990s, even as demand grew dramatically. Production and drilling activities dropped off in the late '90s, leading to declines in published reserve statistics. Increased activity in 1999, however, led to slight increases in reserve numbers by the end of 1999. It remains to be seen whether accelerated exploration in 2000 and 2001 will yield substantial new discoveries.

Potential New Sources of Natural Gas

Coal Bed Methane

One of the more promising new sources of natural gas in the western U.S. is coal bed methane. This is natural gas which is contained in deep underground coal formations. While the coal itself may not be economical to mine, the gas can be tapped by drilling into the coal bed. Estimated amounts of coal bed methane in western producing areas are shown in the table below.

Estimated coal bed methane sources of gas are almost equal in size to the total proven reserves of conventional natural gas, and are less than 10% developed at the present time. Therefore, while conventional gas resources are unlikely to be able to meet surging growth in natural gas demand, coal bed methane development could contribute significantly to meeting natural gas demand. In addition, since virtually all of the coal bed methane potential is in the Rocky Mountain region, all of it is available to the Pacific Northwest over the current route of Northwest Pipeline, although major capacity upgrades would be required. In 1998, about 6% of U.S. gas production was from coal bed methane sources.³²

Table 4.2. Estimated Coal Bed Methane, Total U.S. Undiscovered Reserves

Powder River Basin (Montana, Wyoming)	39 Tcf
San Juan Basin (New Mexico)	84 Tcf
Uinta Basin (Utah)	10 Tcf
Raton Basin (Colorado)	10 Tcf
<i>Total</i>	<i>143 Tcf</i>

Source: Barrett Resources Corporation³³

Developing coal bed methane is expensive and involves environmental issues not present with conventional gas production. A normal deep conventional well producing natural gas can be drilled and tapped with multiple wells emanating from a single drilling platform, and the impact on adjacent properties is relatively small. Coal bed methane requires large wells located close together, and huge amounts of water must be pumped out in order to free up the gas. The water must either be reinjected into wells, or else disposed of on the surface. Pumping the water is energy-intensive and expensive. Reinjection of the water is also energy intensive, very expensive, and adversely affects the economics of coal bed methane production. Surface disposal of the water carries environmental impacts which are considerable.

³² EIA U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1998 Annual Report, P. 35

³³ U.S. Rockies: Non-Conventional Supply Is Growing, J. Frank Keller, Executive Vice President & CFO. Barrett Resources Corporation, June, 2000

Drilling for gas is taking place at record pace. Colorado has granted some 10,000 new well permits in the past seven years, with permits in 1998 and 1999 at double the rate of the previous years. Natural gas production has increased by 80% in this period. However, the state estimates that 100,000 new wells would be required to fully develop the coal bed methane resource in the state.³⁴ The state is moving towards a requirement for directional drilling, which would tend to increase costs while reducing adverse impacts on surface land owners.

The cost of coal bed methane development is extremely competitive in the current gas market³⁵, but costs will likely increase in the future as well size decreases and environmental concerns begin to be addressed. In Colorado, ranchers who previously tolerated or even encouraged deep well natural gas drilling are organizing in opposition to coal bed methane development because of the large number of wells required. In Wyoming, opposition to surface disposal of water is becoming a political issue.³⁶

Alaska

The state of Alaska has considerable remaining proven natural gas reserves, totaling some 10 Tcf. At current rates of production, Alaska has about a 20-year supply of proven reserves. This supply is comfortably adequate to meet in-state demands for many years, and to support existing exports (a small liquefied natural gas export facility near Anchorage ships gas to Japan), but is not large enough to meet demand in the lower 48 states for very long. The total proven reserves of Alaska would meet domestic demand for only about six months.

However, this number does not include gas in remote areas that cannot be produced without major infrastructure improvements. Up to 35 Tcf of natural gas deposits are estimated to exist in oil-producing regions on Alaska's North Slope. It is highly likely that additional reserves will be discovered if and when a means for this gas to reach consumers in the lower 48 states is developed.

A number of projects are under consideration that would bring Alaska gas to markets in Canada and the lower 48 states. One route would be a pipeline along the McKenzie River to interconnect with the existing Canadian pipeline system in Alberta and British Columbia. Another route, reportedly favored by Alaska politicians, would parallel the existing oil pipeline to Fairbanks, and then follow the Alaska-Canada Highway into northern British Columbia. Other options include a liquefied natural gas project, which would pipe gas to Valdez, chill it into a liquid, then ship it to Asia, and a gas-to-liquids project that would refine gas into a liquid called "white crude" that could flow through the oil pipeline.

New Canadian Sources

Currently, virtually all natural gas imported from Canada comes from conventional gas wells in the Western Canadian Sedimentary Basin. Other Canadian gas sources should be expected to be developed if demand continues at higher prices.

³⁴ Colorado Oil & Gas Development in the New Millennium, Colorado Oil and Gas Conservation Commission, January, 2000

³⁵ The Fort Union Coal Bed Methane project reports that 4-16 Tcf can be recovered at costs of \$.30 - \$.45/mcf. This is about one-tenth of long-term estimated wholesale gas prices. Presentation by Frank Keller, Barrett Resources Corporation, Ziff Energy Gas Conference, June, 2000.

³⁶ Backyard Boom, High Country News, September 25, 2000

First, there are substantial coal bed methane gas resources in the WCSB. Undiscovered Reserves of coal bed methane gas are estimated at 75 Tcf, about a ten-year supply at current production rates. Second, there are so-called “Frontier” gas resources, which are in the far north of Canada. These are estimated to represent as much as 300 Tcf of Undiscovered Reserves, of which no estimate can be made of the proportion that will be economic to produce. The cost of development of these resources in the remote, frozen North are quite considerable, but the success of the Alaska North Slope oil development suggests that it is not necessarily outside of the economic potential for the future. If developed, together with the long-distance pipelines needed to bring this gas to markets, these resources would add several decades to the supply of Canadian natural gas. The prices would likely be higher than we have historically experienced for natural gas.

Potential for Importing Liquefied Natural Gas

If the price of natural gas stays high enough for long enough, it may become economic to invest in large-scale facilities for importing liquefied natural gas (LNG). Liquefying natural gas requires refrigerating the gas to -265° Fahrenheit. It can then be moved by ship to a receiving terminal, where it is vaporized, compressed, and injected into the pipeline distribution system. It is both a capital-intensive and an energy-intensive process.

The U.S. currently exports a small amount of LNG from Alaska to Japan, and imports a small amount from Algeria to the East Coast. Japan and Korea are the world’s largest importers of LNG, together receiving about eighty percent of the total amount shipped worldwide.

LNG poses both technical challenges and physical risks. Only one commercial LNG facility has ever failed in operation, but it caused catastrophic damage to Cleveland, Ohio in 1944.³⁷ Since that time, LNG facilities have been generally limited to remote locations. The typical size of an LNG tank today is around 3 Bcf, or 30 times as large as the one that failed in Cleveland.

Because world producers of gas have such huge supplies relative to North America, LNG is a “backstop” resource which could augment pipelines supplies if the economics were promising to investors. It is estimated that a price of \$4-5 per MMBtu would be required to support LNG shipping and receiving facilities.³⁸

Increased imports of LNG in the short term are most likely to come from the Middle East, where vast natural gas reserves remain largely untapped, to the East Coast. This would have the effect of displacing gas from conventional sources such as the Gulf Coast, potentially freeing up some supplies for West Coast markets. El Paso Energy recently announced plans to develop several LNG import facilities in the U.S. and Bahamas for import to the U.S., and Williams is in the process of expanding a facility in Maryland. In the longer term, LNG could be imported to the West Coast from terminals in Alaska or the Far East. El Paso also recently announced a joint venture with Phillips Petroleum to begin shipping LNG from Australia to California markets in 2005. Chevron Corp. has announced similar plans.

³⁷ From the Encyclopedia of Cleveland History, Case Western Reserve University:

The EAST OHIO GAS CO. EXPLOSION AND FIRE took place on Friday, 20 Oct. 1944, when a tank containing liquid natural gas equivalent to 90 million cubic feet exploded, setting off the most disastrous fire in Cleveland's history. Homes and businesses were engulfed by a tidal wave of fire in more than 1 sq. mi. of Cleveland's east side, bounded by St. Clair Ave. NE, E. 55th St., E. 67th St., and the MEMORIAL SHOREWAY. The fire destroyed 79 homes, 2 factories, 217 cars, 7 trailers, and 1 tractor; the death toll reached 130.

³⁸ Energy Information Administration, Natural Gas Monthly, August, 1997

Implications

While new gas supplies are being located and developed continuously, the cost of new supplies will likely continue to rise. This is due to diminishing reserves among traditional large-pool resources, higher costs associated with reaching smaller pools of gas, higher costs of bringing large new sources of gas such as Canadian Frontier gas, Alaska gas, or liquefied natural gas to the lower 48 states. Higher costs are also likely due to additional environmental restrictions on development of coal bed methane.

Higher development costs would translate into increased prices for consumers of natural gas in Washington. While this report makes no attempt to predict prices in an extremely dynamic market, it appears that wholesale gas prices in the \$3.50-6.00 per MMBtu range would be necessary to spur large-scale development of new gas resources from small pools, from Canadian Frontier or Alaska sources, from coal bed methane (with stricter environmental regulation), or from imports of liquefied natural gas. A number of alternatives to natural gas become economic at prices in that range, especially for electricity generation.

At the same time, improved technology can work to lower the cost of finding and developing new sources. The interaction between technological innovation reducing gas development costs, decreasing gas production from existing wells, and declining pool size causing an increase in development costs is a matter of some conjecture. Because of all the different uncertainties, neither the rate of change nor even the direction of change in gas price can be predicted with certainty.

Section 5. Conclusions and Recommendations for Further Study

This report examines trends in the demand for and supply of natural gas for Washington and the Pacific Northwest. It identifies proposed natural gas-fired power plants as a major new source of demand, analyzes the current capacity of the region's delivery system to meet this demand, and identifies potential sources of pressure on the price and supply of natural gas, both short- and long-term. This section summarizes the major conclusions from this study, and suggests some responses on the part of policy-makers and industry participants.

Wholesale electricity and natural gas prices are subject to extreme price volatility, and increasing convergence of the electricity and natural gas markets means that extreme events are likely to affect both markets simultaneously.

While this conclusion may seem obvious in light of the events of the past several months, it is evident that the risks of price volatility were greatly underestimated by policy-makers, regulators and industry participants. Enhanced understanding of the potential for extreme price volatility will have a number of important consequences:

- Electric utilities may wish to review resource plans in light of the newly understood risks. While deregulated wholesale markets made extreme short-term price volatility possible, they have also provided industry participants with a variety of tools to protect against that volatility. These include contract purchases of various lengths and terms, physical instruments such as swaps or options, and financial instruments such as futures or derivatives. Utilities may even decide to reevaluate strategies with respect to ownership of generation resources. Each of these options carries a unique risk profile; the choices made will reflect individual company risk tolerance. The state may wish to consider ways to encourage utilities to maintain diverse resource portfolios.
- However, the potential for simultaneous price spikes in electricity and natural gas markets means that ownership of natural gas-fired resources may not provide much of a price hedge for electric utilities. Options for hedging natural gas price risk are similar to those described above for electricity. Alternatively, utilities may wish to consider fixed cost resources such as wind generation; plans to ramp up investments in wind have already been announced by PacifiCorp, Energy Northwest, and BPA, among others. Energy efficiency investments will look increasingly attractive -- BPA also announced that its conservation and renewables discount program will begin several months earlier than planned. If gas prices remain high, new coal or nuclear generation may be proposed. The state may wish to encourage additional investment in energy conservation and renewable resources as a hedge against volatile natural gas prices.
- Regulatory policies can have a major impact on company purchasing strategies. Natural gas utilities in Washington are insulated from market price volatility through Purchased Gas Adjustment (PGA) mechanisms, which allow fuel price risk to be passed to consumers through rates that are adjusted based on the costs of utility gas purchases. The PGA incentive mechanisms adopted in 1998 give utilities the incentive to make most of those purchases at monthly market indexes. The WUTC may wish to review existing policies to ensure that they provide appropriate incentives for companies to make good resource management decisions and to offer consumers some measure of protection from bad ones. Do current regulatory policies align the utility's interest in avoiding risk with the customer's

interest in lower natural gas prices? Do they encourage too much dependence on market indexes and discourage the use of longer-term, fixed price contracts that may provide more price stability? Do they properly balance competing objectives of price stability and lower costs in times of extreme volatility?

- Retail energy rates that better reflect wholesale market conditions might encourage more conservation during times of tight supplies and high prices, as customers would respond not just to calls for conservation from state and local leaders, but to higher monthly bills. There are a variety of mechanisms that would accomplish this, including prices that vary during a single day, prices that change monthly, increasing block rates where the highest block is at the margin for most customers, and programs that allow credits back to consumers for conserving during times of high market prices. Accompanied with an appropriate true-up to ensure that utilities neither over-collect nor under-collect from retail customers, these mechanisms would not result in overall higher bills for retail consumers, but would change the shape of bills to better reflect scarcity in wholesale markets. However, in order for customers to respond appropriately to changing prices, they would need access to timely information about the rates that are in effect at any given time. Utilities and regulators should consider mechanisms that would allow customers to better respond to market conditions while ensuring that customers retain the value of rate-based resources and are given the tools they need to respond to changing rates.

New natural gas-fired power plants will greatly increase the region's demand for gas, even if only a portion of planned projects are actually constructed.

Over 12,000 MW of new natural gas-fired power plants have been proposed for the region. Over 1500 MW are currently under construction, and another 2700 MW possess the necessary permits to begin construction. If even half of these are built over the next ten years, in line with projections by the federal Energy Information Administration, the region's natural gas consumption would increase by 50%. Whether this level of construction creates problems for the industry depends on the timing of both the new power plants coming on line and additions to the region's ability to deliver gas at reasonable prices.

- The state may wish to address as part of the energy facility siting process the combined fuel requirements of all permitted natural gas power plants, so that the public interest in a reliable gas supply is not impaired. A study of the potential cumulative impacts of all approved power plants, if combined with a condition that plants begin construction within a specified period of time after approval, e.g., two to three years, would ensure that these combined impacts are well understood. By providing better information about which projects are most likely to go forward, this would help pipeline companies and others plan for future infrastructure growth, existing gas purchasers better prepare themselves for future market conditions, and policy-makers better understand the potential impacts on local and regional economies.
- The state may wish to study the effect that new natural-gas fired power plants will have on the region's ability to meet simultaneous peak demands on the electricity and natural gas systems. In the Northwest, peak demands for both systems tend to occur on the coldest days of the year. These are the times that are most expensive to serve, both because of scarce commodity supplies and because it is expensive to size delivery networks to meet demands that occur infrequently. Requiring that new generators demonstrate sufficient pipeline or

storage capacity for their peak needs would help alleviate pressure on prices paid by existing natural gas users. However, just increasing local delivery capability will not necessarily result in sufficient new supplies to completely offset the impact. Allowing generators to switch to No. 2 distillate fuel oil (diesel fuel) for a certain number of days per year would be another way to relieve pressure on the natural gas system. This may, in turn, have potential negative consequences for users of diesel and home heating oil; a single 700 MW power plant burning diesel at a 100% capacity factor would increase Washington's daily distillate use by 25%. Burning distillate also results in significantly greater environmental impacts. Policy-makers need to understand the costs and risks of each of these strategies.

- The state may wish to consider policies that would encourage the direct use of natural gas at the customer location for water and space heating in order to reduce the demand for new, natural gas-fired generation. While new power plants are much more efficient than the previous generation, over half of the energy input to new power plants is lost before reaching end-use customers. Burning natural gas to create heat directly at the customer location achieves efficiencies approaching 80%. Although most new homes are now heated by natural gas, there may be additional opportunities to convert existing applications to natural gas that are not being captured.

Increased pipeline capacity from producing areas in Canada and the U.S. Rockies to East Coast and Midwest markets means that the price of natural gas for Northwest customers will be much more closely tied to continent-wide events than in the past.

The impact of this fundamental shift in gas market dynamics has thus far largely been obscured by the extreme forces emanating from the California electricity crisis. For nearly a decade, the Northwest has benefited from the lack of eastbound pipeline capacity, particularly from producing fields in Alberta and British Columbia. The opening of the Alliance Pipeline in November, 2000, with capacity to carry 1.3 Bcf per day of Western Canadian gas to markets in Chicago and the Midwest, effectively marks the end of this era. The Northwest will now feel the effects of cold snaps in the Northeast that drain storage fields across the continent, and will have to compete for gas with new gas-fired generators from California to Florida. The region will feel the effects of increased use of natural gas for electricity generation even if it doesn't build a single new gas-fired power plant. To prepare for this eventuality, and to better understand the dynamics of continental natural gas markets, the state may wish to:

- Examine projected natural gas supply and demand on a continent-wide basis, to determine the likelihood that increased demand in this and other regions can be met with additional supplies, and the effect this will have on competition for and prices of resources that have traditionally supplied the Northwest. This would include an examination of potential sources of new supply in major gas producing regions such as Oklahoma and the Gulf Coast states, and offshore production in the Gulf of Mexico and the Canadian Maritime Provinces. It would also include a more detailed examination of the potential for greatly increased importation of liquefied natural gas from the Middle East to the U.S. East Coast, and to the West Coast from Alaska and the Far East.
- Examine the potential for new sources of natural gas production in areas that will realistically meet future demands in the Northwest. This would include an examination of the economic, technical, and political state of development of new resources in the Rocky Mountain area (including coal bed methane), the Western Canadian Sedimentary Basin, the far North of Canada, and the Alaska North Slope, and an analysis of how gas from those areas may be delivered to this region.

Appendix A. Glossary

Air Basin. A geographical air resource region with similar meteorological and geographic conditions throughout its boundaries, generally defined by mountains or other natural barriers.

Backstop Resource. A theoretical concept representing the price at which some alternative resource will become available in large quantities. The cost of the backstop resource acts as a cap on resource costs in the long run.

Bundled Utility Service. The provision of a variety of utility services including energy commodity, delivery, metering and other services under a single tariff generally regulated by a state utility commission.

Burner Tip. A generic term used to mean the final end-using equipment for natural gas. It may be an industrial boiler, residential clothes dryer, or any other actual use of natural gas.

Coal Bed Methane. Methane that is trapped by water in a coal bed. To access this gas, the water is pumped out until enough pressure is released to unleash the gas.

Cogenerator. A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes.

Combined Cycle Power Plant. An electric generating plant that consists of one or more combustion turbines and one or more boilers with a portion of the required energy input to the boiler(s) provided by the exhaust gas of the combustion turbine(s).

Core Market. Natural gas customers, typically residential, commercial, and small industrial users, that purchase gas commodity as part of bundled service from their local distribution company.

Deliverability. The daily capacity of the natural gas transmission and/or distribution system to provide gas flows.

Delivery point. A point on an interstate pipeline at which the pipeline can deliver flows of natural gas to another system, e.g., another interstate pipeline, LDC system, transportation customer, or storage facility.

Design Day. The coldest day or days of recent historical record. Delivery systems such as interstate pipelines and LDC systems are sized to meet design day demands on a planning basis.

Displacement. The practice of allowing flows to be nominated that are greater than the maximum delivery capability of a particular pipeline segment, made possible due to firm nominated flows by other shippers in the opposite direction.

Endowment. Total amount of gas available in a geographical area prior to the development of any gas wells; the theoretical sum of gas already produced, gas available from remaining marketable reserves, gas which has been located but is not producible and marketable, and gas which is in undiscovered reserves.

Energy Efficiency Programs. Programs that are aimed at reducing the energy used by specific end-use devices and systems, generally without affecting the quality of services provided.

Energy Facility Site Evaluation Council (EFSEC). Washington's Energy Facility Site Evaluation Council, the siting and permitting agency for major energy facilities in Washington.

Energy Information Administration. A branch of the United States Department of Energy that provides energy statistical information to the public. Accessible at www.eia.doe.gov

Federal Energy Regulatory Commission (FERC). A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Firm Gas. Gas supplies and transportation services that have assured availability through contractual or tariff provisions, i.e., that cannot be interrupted to meet the needs of other customers under adverse conditions.

Frontier Gas. Gas from northern Canada, or Alaska North Slope.

Gas Marketer. A company that buys gas from gas producers or other marketers in wholesale quantities, and sells it to other marketers, LDCs or transportation customers.

Gas Producer. A company that extracts natural gas from wells and delivers it to an interstate pipeline for delivery to its customers.

Gas Turbine. A generating technology that typically consists of an axial-flow air compressor and one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine and where the hot gases expand to drive the generator and are then used to run the compressor. A jet engine is a form of gas turbine.

Geothermal Energy. Energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted either as hot water or steam by drilling and/or pumping.

Interstate Pipeline. A pipeline that connects gas producers to LDCs and transportation customers. There are two interstate pipelines in Washington, Northwest Pipeline and GTN.

Liquefied Natural Gas (LNG). Natural gas that has been compressed and chilled to -265° Fahrenheit, when it turns to liquid, for storage or ship transport.

Local Distribution Company (LDC). Natural gas utilities that receive natural gas from interstate pipelines and deliver it to end-use customers either as part of bundled retail service or on behalf of a third party gas supplier, typically at rates regulated by states.

Looping Pipe . Pipe that is laid parallel to existing pipe within the same right-of-way in order to increase delivery capacity.

Market Hub or Market Center. A particular geographic location at which energy and other products are exchanged; buyers and sellers must arrange transportation services to and from the specified point. The primary hubs affecting the Pacific Northwest are at Sumas, Washington, Kingsgate, British Columbia, and Opal, Wyoming.

National Energy Board (Canada). A federal energy agency of Canada, which regulates gas pipeline rates and grants permits for natural gas exports.

Natural Gas. A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane (CH₄).

Nomination. The practice of requesting a natural gas flow on an interstate pipeline for a particular day through the identification of injections and withdrawals at particular receipt and delivery points.

Non-firm (or Interruptible) Gas. Gas sold to customers with a provision that permits curtailment or cessation of service at the discretion of the distributing company under certain circumstances, as specified in the service contract, having limited or no assured availability.

Northwest Power Planning Council (NWPPC). A four-state compact formed by Idaho, Montana, Oregon and Washington to oversee electric power system planning and fish and wildlife recovery in the Columbia River Basin. The Council was initiated by Congress through approval of the Northwest Power Act of 1980 (Public Law 96-501).

Open Season. A process during which shippers of natural gas can contract with pipeline companies for firm delivery capacity. An open season is typically conducted in conjunction with a pipeline expansion, but it can also include firm capacity that has been “turned back” by shippers to the pipeline for resale.

Operational Flow Order (OFO). An order issued to alleviate conditions, inter alia, which threaten or could threaten safe operations or system integrity of the transportation service provider's system or to maintain operations required to provide efficient and reliable firm service.

Peak Demand. The maximum instantaneous demand placed on an electric or natural gas delivery system.

Proven Reserves. A dynamic statistic that measures the amount of gas available in a defined area that is economic to produce at current prices.

Public Utility Regulatory Policies Act (PURPA). 1978 Act of Congress which allowed for independent (non-utility) ownership of power plants.

Purchased Gas Adjustment (PGA). Retail ratemaking mechanism through which LDCs pass through wholesale natural gas costs to their retail customers, subject to review and audit by state utility commissions.

Receipt point. A point on an interstate pipeline at which the pipeline can receive flows of natural gas from another system, e.g., another interstate pipeline, producing field or storage facility.

Segmentation. The practice of dividing firm capacity from a particular receipt point to a particular delivery point on an interstate pipeline into smaller segments based on intermediate receipt and delivery points to facilitate resale of the capacity on the secondary market.

Shipper. A gas producer, marketer, or consumer holding a contract for firm capacity on an interstate natural gas pipeline.

Simple Cycle Power Plant. An electric generating plant, typically used to meet peak demands, that consists of one or more combustion or steam turbines with no recovery of heat from exhaust gases.

Spark Spread. The margin available to the operator of a power plant, given natural gas and electricity prices and a plant-specific heat rate. It represents the maximum a power plant operator would be able to pay above the actual price of gas and still operate profitably.

Spot Market. A market, either formal or informal, in which energy, delivery capacity and other products are exchanged on a short-term, e.g., daily or hourly, basis.

Supply Basins (Rocky Mountain, San Juan, Western Canada Sedimentary). North American regions where dense natural gas reserves are located and where the majority of our current supplies originate. Extensive drilling and refining occur in parts of these regions.

Tariff. A set of rates, terms and conditions of utility service regulated by a federal, state or local commission.

Transportation Customer. A large natural gas customer that purchases transportation services from LDCs but purchases natural gas commodity directly from gas producers or gas marketers.

Unbundling. The process of separating and offering separately the variety of services that have traditionally been included in bundled retail utility service.

Unconventional Gas Resources. Natural gas recovered from such sources as tight sands, coal bed methane, and gas shales; these resources are generally more difficult and expensive to recover than conventional resources.

Undiscovered Reserves. Amounts of gas that are estimated to be developable at reasonable cost, but that have not yet been added to proven reserves, a portion of which is assumed to be capable of being produced and brought to market at profitable prices.

Utilities. Companies, either privately, cooperatively, or publicly owned, that provide utility services such as electricity, natural gas, water, sewer, cable television, and/or telecommunications to retail customers.

Washington Utilities and Transportation Commission (WUTC). An agency of the Washington state government with statutory responsibility for regulating the rates, terms and conditions of retail utility services provided by investor-owned utilities. The WUTC also regulates the services of some transportation companies and has some public safety responsibilities for in-state pipelines and railroads.

Wholesale Market. Sales of energy for resale; wholesale energy markets are regulated by the Federal Energy Regulatory Commission.

Appendix B. Units of Measure

Btu	British thermal unit, a standard unit of energy content. One Btu is the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.
Mbtu	1,000 Btu.
Therm	100,000 Btu. One therm contains roughly the same amount of energy as one gallon of gasoline (125,000 Btu). Retail natural gas sales are typically measured in therms.
MMBtu	One million Btu.
Dth	Decatherm. Equal to 10 therms, or 1,000,000 Btu (1 MMBtu). Wholesale natural gas sales are typically measured in Dth.
MDth	Thousand Decatherms, or 1,000 MMBtu.
KW	Kilowatt. A standard unit of instantaneous electric energy generation or delivery capability, equal to 1000 Watts.
MW	Megawatt. Equal to 1,000 kW. The standard unit for expressing power plant generation capacity. The highest instantaneous energy demand of the city of Seattle is approximately 2,000 MW.
kWh	Kilowatt-hour. Standard unit of electric energy content representing the output of a 1 kW generator operating for one hour. One kWh if used to produce heat such as hot water or cooking, is equal to 3,412 Btu. Retail sales of electricity are typically measured in kWh.
MWh	1,000 kWh. Wholesale sales of electricity are typically measured in MWh.
aMW or MWa	Average Megawatts. A unit of electric energy content representing the output of a generator operating at 100% capacity for an entire year. Equal to 8,760 MWh.
cf	Standard unit for measuring volume representing one cubic foot of natural gas at standard temperature and pressure.
Mcf	Thousand cubic feet. One thousand cubic feet of natural gas contains approximately 1 MMBtu (or 1 Dth) of energy.
MMcf	Million cubic feet. One million cubic feet of natural gas contains approximately 1,000 Mmbtu (or 1,000 Dth) of energy.
Bcf	Billion cubic feet.
Tcf	Trillion cubic feet. Natural gas reserves are typically expressed in Bcf or Tcf.
MMcf/d	Million cubic feet per day. A measure of the rate of gas flow through an interstate pipeline.
Bcf/d	Billion cubic feet per day. A measure of the rate of gas flow through an interstate pipeline. 2 bcf/d is a large pipeline.